Developing and Updating Output-Based

NOx Allowance Allocations

Guidance for States Joining the NOx Budget Trading Program

under the NOx SIP Call

May 8, 2000

U. S. Environmental Protection Agency

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Preface

This document assists State environmental agencies as they consider adopting output-based NOx allowance allocations for their State implementation plan (SIP) in response to the NOx SIP call. It focuses on technical issues of how to develop and implement output-based allowance allocations. In particular, this document describes options for developing NOx allowance allocations for power plants and industrial (or institutional) boilers and turbines using output (electric generation or thermal energy). The discussions in this document may also help others plan and understand regulatory requirements.

This document describes how you could allocate NOx allowances using output data and how you could obtain information that will let you update those allocations periodically. The focus of this guidance is for States creating a NOx trading program.

The guidance document provides examples of how to calculate NOx allowance allocations using electric output and thermal output data and how to adjust these allocations to fit a State's sector budgets for electric generating units and non-electric generating units. The guidance considers:

- The types of facilities to which the guidance applies
- The assignment of allocations to units, to plants, or to generators
- Technical and policy concerns in selecting the location for measuring or calculating output data to be used in allocations
- Requirements for sources, such as monitoring, recording, and reporting output data
- Potential sources of output data
- Regulatory provisions to include in State rules

Finally, the document provides sample regulatory language that would revise the Model NOx Trading Rule for the NOx SIP call at 40 CFR part 96.

This guidance does not give a comprehensive discussion of policy issues for choosing a particular approach to allocating NOx allowances. However, it includes a brief discussion of the analysis we considered while evaluating updating output-based allocations in our January 18, 2000 section 126 final rule.

This guidance does not give recommendations about how often you should update allocations, to which sources you should allocate NOx allowances based on output, or whether you should use gross or net output data as the basis for allocations. The Updating Output Emission Limitation Workgroup, which assisted us in developing this guidance, did not address or resolve such issues. We ourselves are still considering the last two of these issues and intend to take public comment on them in an upcoming rulemaking in the year 2000. The legal issues and many policy issues associated with adopting an output-based allocation are beyond the scope of this document. However, the guidance document does raise issues for you to consider as you decide on the most appropriate approach to allocating NOx allowances in your State.

In the model rule for the NOx Budget Trading Program under the NOx SIP call, 40 Code of Federal Regulations (CFR) part 96, we provided an approach to allocating NOx allowances based on heat input. We did this primarily because we had successfully established allocations based on heat input for previous programs, and had concerns about issues of implementation and data quality with output-based allocations. However, in the final NOx SIP call, we also committed to working together with stakeholders to resolve these issues in order to design an approach to allocating output-based NO_X allowances that States could use as part of their trading program rules in their SIPs. We said that we would develop a proposed approach to output-based allocations in 1999 and finalize an output-based option in 2000. We issued draft guidance in December of 1999. Today's document is the final guidance to States for output-based allocations that we committed to in the NOx SIP call.

You will find some new challenges in setting allocations based on output, rather than heat input. This guidance addresses many of these challenges. The guidance document is laid out as follows:

- Section I describes various output-based emission limitations and references EPA's analysis of approaches to allocating NO_X allowances for the final section 126 rule.
- Section II addresses how to calculate NOx allowances for sources that produce both electricity and heat or steam as useful outputs.
- Section III describes the types of sources to which this guidance applies.
- Section IV discusses allocating NOx allowances to units, to generating systems, or to

entire plants.

- Section V describes technical and policy concerns in selecting the location for monitoring or calculating output data to be used for allocations.
- Section VI describes where sources do, or could, monitor electric and thermal output at different types of facilities.
- Section VII addresses how sources would monitor and report information on electric or thermal output.
- Section VIII describes potential sources of output data and their limitations.
- Section IX suggests changes that you may want to make to your State rule to include updating, output-based allocations.
- Section X gives you background on how we considered issues in preparing this guidance and suggests additional sources of information.
- Appendix A provides language that you may use or modify for use in your State implementation plan if you determine NOx allowance allocations based on output.
- Appendix B is a glossary to help you understand terms and abbreviations.

We hope you will find this draft guidance to be useful and informative.

Acknowledgments

EPA developed this document through the efforts of the Updating Output Emission Limitation Workgroup. The Updating Output Emission Limitation Workgroup is a workgroup of the Clean Air, Energy and Climate Change Subcommittee of the Clean Air Act Advisory Committee. Workgroup members include representatives of the electric power industry, district energy groups, industrial boiler owners, the natural gas supply industry, environmental groups, State environmental agencies, labor unions, and other organizations. From December 1998 through December 1999, we held a series of meetings and conference calls. The workgroup prepared a number of issue papers, discussed issues, and reviewed and provided comments on a draft version of this guidance document.

Although this document does not reflect all views expressed by the Updating Output Emission Limitation Workgroup, we could not have developed this document without the knowledge and the perspectives that the workgroup shared with us. We thank the members of the Updating Output Emission Limitation Workgroup for their many contributions.

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Table of Contents

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List of Figures

List of Tables

I. Background: Why should I consider using output-based NOx allowance allocations?

Traditionally, emission limitations have been based on the concentration of pollutant (e.g., sulfur) in fuel, on the concentration of pollutant in the flue gas, or on the amount of pollutant per unit of input to the process; for example, many power plants and industrial boilers meet emission standards in pounds of pollutant per million British thermal units (mmBtu) of heat input (fuel usage). In recent years, there has been increasing interest in setting emission limitations based on the amount of pollutant per unit of useful output or product of a process. Some emission limitations have always been on the basis of the amount of pollutant produced per unit of output, such as vehicle emission standards in grams per mile traveled or standards for stationary internal combustion engines in grams per horsepower-hour. More recently, EPA adopted revised New Source Performance Standards for new power plants in terms of pounds of NOx per megawatt-hour of electric output.

In theory, a power plant or boiler could reduce pollution by improving its efficiency and could produce the same amount of electricity or steam from less fuel. This would be an alternative to complying with an emission limitation by using cleaner inputs to the process or by putting on emission controls. Advocates of output-based emission limitations have suggested that using output as the basis for an emission limitation encourages greater efficiency and potentially reduces air pollution.[1]

You can also use an output measure when allocating allowances under a cap and trade system. Such allocations are typically determined using one or more emission rate values and information on the sources' operating history. In the Acid Rain Program and Phase II of the OTC NOx Budget Program, regulators calculated allocations for sources using the product of an emission

[1]Others disagree with this point of view. They point out that industry already has a significant incentive to improve efficiency by saving on fuel costs. Some commenters on the draft guidance stated that making significant changes to existing facilities may make sources subject to New Source Review requirements, which could be cost prohibitive. Comments of the American Forest & Paper Association Regarding the U.S. EPA's Draft Guidance on Output-Based Allocations for States Joining the NOx Budget Trading Program under the NOx SIP Call; Technical Comments of Cinergy Corp. on EPA's Draft Guidance on Output-Based Allocations for States Joining the NOx Budget Trading Program under the NOx SIP Call, January 12, 2000; Comments on Output Based NOx Allowance Allocations, November 29, 1999 Draft Guidance Document from Indianapolis Power & Light, January 10, 2000.

rate factor in pounds of SO_2 or NO_X per million Btu (mmBtu) or heat input and the historic heat input in mmBtu from a particular period of time. However, you could also use an emission rate factor in lb SO_2 or NOx/MWh and the historic electric output in MWh from a power plant to determine its allocation. For specific examples of how to calculate allowance allocations, see section II of this document (pp. 23-43). Note that output-based allowance allocations under a cap and trade program do not necessarily provide the same incentives or result in the same consequences as an output-based emission standard using a rate which is applied without a cap. In particular, if you update output-based allocations periodically using recent data, you may encourage increased utilization in addition to increased efficiency by sources vying for a larger share of the allocations.

In EPA's section 126 final rule, we created a Federal NOx Budget Trading Program that covers many of the same States included in the NOx SIP call. Unlike the NOx SIP call, EPA is responsible for developing NOx allowance allocations under the section 126 final rule. We evaluated potential impacts of different NOx allowance allocation methods as part of EPA's section 126 final rule (January 18, 2000). See 65 FR 2698-2711 for a detailed discussion of how EPA decided on the allocation methodology for the section 126 rule. We analyzed impacts of permanent allocations versus updated allocations. Our analysis of different allocation approaches also considered the potential impacts of updating allocations using heat input, using output of fossil fuel-fired electric generating units[2], and using output of both fossil fuel-fired electric generating units and non-emitting electricity generating systems. In particular, the study looked at impacts on emissions and generation from the electricity industry. It did not examine potential impacts on non-electric generating units (e.g., industrial or institutional boilers and turbines). You can find the results of the analysis as well as a description of the methodology in the report, "Economic Analysis of Alternative Methods of Allocating NOx Emissions Allowances" (EPA Air Docket A 97-43, Category XI-B-01; this also is available on EPA's web site [http://acidrain/modlrule/main.html#126]). You may consider this report as you decide whether you wish to use output-based or updating allocations.

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[2] This includes the sources that EPA defined as "electric generating units" in the final NOx SIP call of October 18, 1998, including some cogeneration facilities. The D.C. Circuit Court of Appeals has remanded the definition to EPA for further consideration. See State of Michigan v. U.S. EPA, No. 98-1497, slip op. at 28-29 (D.C. Cir., March 3, 2000).

Our allocation report examined the question of allocations only in the context of NOx emissions and the NOx Budget Trading Program, and its results should be interpreted only in that context. Future decisions on allocations for potential future cap-and-trade programs should be based on analysis specific to those programs.

II. Calculations: How do I calculate source allocations?

A. What formula(s) do I use to calculate NOx allowance allocations based on output?

Use the following formulas:

For calculating NOx allowance allocations from electric output:

$$\text{Allocation} = \left(\frac{1.5 \text{ lb } NO_x}{\text{MWh}}\right)\left[\frac{\begin{array}{l}\text{Electricity generation during}\\ \text{baseline period, in MWh}\end{array}}{2000 \text{ lb / ton}}\right]$$

Eq. 1

Where:

"Allocation" is the unadjusted NOx allowance allocation, in tons.

1.5 lb NOx/MWh is the factor for allocating NOx allowances based on electric output.

"Electricity generation during baseline period, in MWh" is the electricity generation in the time period that you choose. For example, this could be the average electricity generation during the ozone season for the two years with the highest generation out of 1995, 1996, and 1997.

For calculating NOx allowance allocations from thermal output:

In this document, we present two general approaches to measuring thermal output. Depending on the approach you require for monitoring thermal output, the value of the measured thermal output and the factor used in the formula will vary. The two approaches to monitoring thermal output, the boiler efficiency approach and the simplified approach, differ in whether sources must measure and subtract out all thermal energy that returns to a boiler. See the discussion in section VI. , "Where do facilities measure electric and thermal output?"(pp. 55-141, especially pp. 68-69). The derivation of the factor is discussed further below in this section.

If you are using the boiler efficiency approach for monitoring thermal output, use the following equation:

$$\text{Allocation} = \left(\frac{0.24 \text{ lb } NO_x}{\text{mmBtu}_{out}}\right)\left[\frac{\text{Measured thermal output during baseline period, in mmBtu}_{out}}{2000 \text{ lb / ton}}\right]$$

Eq. 2

Where:

"Allocation" is the unadjusted NOx allowance allocation, in tons.

0.24 lb /mmBtu_{out} is the factor for allocating NOx allowances based on thermal output, as measured using the boiler efficiency approach.

"Measured thermal output during baseline period, in mmBtu_{out}" is the electricity generation in the time period that you choose. For example, this could be the average thermal output during the ozone season for the two years with the highest generation out of 1995, 1996, and 1997. Sources will measure the thermal output using the boiler efficiency approach as described in section VI (pp. 68-69, 84-91, and 124-137). (This monitoring approach requires sources receiving allowances based on thermal output to measure and subtract all thermal energy returning to the boiler.)

If you are using the simplified approach for monitoring thermal output, use the following equation:

$$\text{Allocation} = \left(\frac{0.22 \text{ lb } NO_x}{\text{mmBtu}_{out}}\right)\left[\frac{\text{Measured thermal output during baseline period, in mmBtu}_{out}}{2000 \text{ lb / ton}}\right]$$

Eq.3

Where:

"Allocation" is the unadjusted NOx allowance allocation, in tons.

0.22 lb /mmBtu_{out} is the factor for allocating NOx allowances based on thermal output, as measured using the simplified approach.

"Measured thermal output during baseline period, in $mmBtu_{out}$" is the electricity generation in the time period that you choose. For example, this could be the average thermal output during the ozone season for the two years with the highest generation out of 1995, 1996, and 1997. A source will measure the thermal output using the simplified approach, as described in section VI (pp. 68-69, 74-78, and 102-109). (In this approach, a source does not need to measure the thermal energy going to the boiler in a boiler feedwater return (condensate return) line.)

Sources of the factors (1.5 lb/MWh, 0.24 lb/$mmBtu_{out}$, or 0.22 lb/$mmBtu_{out}$):

Each allowance allocation includes a factor, in terms of mass of pollutant per measurement unit of operation. The factor is multiplied by some measure of unit operation during a baseline period, such as heat input in mmBtu or electric output in MWh. In § 96.42, EPA provided factors of 0.15 lb NOx/mmBtu heat input for electric generating units and 0.17 lb NOx/mmBtu heat input for non-electric generating units. These factors correspond to the average NOx emission rate across the entire sector after making reductions. In the model rule for the NOx Budget Trading Program under the NOx SIP call, every unit in a sector would receive an initial, unadjusted allocation that is based on the same factor. The initial allocation number is then adjusted up or down so that total allowances in the sector would not exceed the State emission budget for that sector. Thus, the exact value of the factor is not important, provided that the allocations are adjusted separately for the electric generating unit sector and for the non-electric generating unit sector. The factor is not an emission standard that a source must meet.

The suggested factors based on output are by the type of energy, rather than by the type of facility. You could use the thermal output emission rate of 0.24 (or 0.22) lb/$mmBtu_{out}$ with thermal output either from a non-electric generating unit that produces only thermal output or for the thermal output of a cogeneration unit that produces both electricity and thermal output. You would not use that factor only for thermal output from non-electric generating units. Likewise, you could use the electric output emission rate of 1.5 lb/MWh for setting an output-based allocation from any facility that generates electricity.

≤ <u>Factor for electric output</u>

If an electricity generating unit with an average heat rate of 10,000 Btu/kWh meets the NOx SIP call target NOx emission rate of 0.15 lb/mmBtu heat input, it will also meet a NOx emission rate of 1.5 lb/MWh. Industry sources and environmental groups have suggested this average heat rate of 10,000 Btu/kWh[3]. This is a heat rate value typical of a large coal-fired boiler using a steam turbine, a commonly-used technology. Utility boilers and turbines typically have heat rates ranging between 8,500 Btu/kWh and 14,250 Btu/kWh[4]. If you wish to, you may calculate your own factor for electric generation using the following equation:

$$\left[\frac{0.15\ \text{lb NOx}}{\text{mmBtu}}\right]\left(\frac{1\ \text{mmBtu}}{10^6\ \text{Btu}}\right)\left[\text{typical heat rate in }\frac{\text{Btu}}{\text{kWh}}\right]\left(\frac{10^3\ \text{kWh}}{1\ \text{MWh}}\right) = \text{factor in }\frac{\text{lb NOx}}{\text{MWh}} \qquad \text{Eq. 4}$$

Alternatively, you may calculate the factor for electric generation by dividing the emissions budget for the electric generating unit sector by the total generation from all affected electric generating units for an ozone season during some baseline period, if you know these numbers.

≤ <u>Factor for thermal output measured by the boiler efficiency approach</u>

We use the term "boiler efficiency" to mean efficiency of imparting thermal energy to steam in a boiler. This is calculated as the thermal output leaving a boiler (not an entire steam system), minus any thermal energy reentering the boiler, divided by the heat input from fuel. This is consistent with the boiler efficiency approach to measuring thermal output, as described in section VI (pp. 68-69, 84-91, and 124-137).

If an industrial boiler with a boiler efficiency of 70% meets a NOx emission rate of 0.17 lb/mmBtu heat input, it will also meet a NOx emission rate of 0.24 lb/mmBtu_{out}. Industrial boilers have efficiencies ranging from 55% to 85%[5]. Existing fossil fuel-fired boilers can readily achieve

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[3]This value was suggested at the February 3 Meeting of the Updating Output Emission Limitation Workgroup.

[4]This is the range of heat rates used in the Integrated Planning Model. EPA has used this model for much of its economic analysis.

[5]Information provided by the American Forest and Paper Association, in a letter entitled, "Comments of the American Forest & Paper Association on Output-Based Emission

an efficiency of 70%. Also, an efficiency of 70% is in the middle of the range of efficiencies for industrial boilers using commonly available technology. If you wish to, you may calculate your own factor for thermal output using the following equation:

$$\frac{\left[\dfrac{0.17\ \text{lb NOx}}{\text{mmBtu input}}\right]}{\text{typical boiler efficiency, as a decimal}} = \text{factor in } \frac{\text{lb NOx}}{\text{mmBtu output}}$$

Eq. 5

≤ <u>Factor for thermal output measured by the simplified approach</u>

In the simplified approach to monitoring thermal output, the owner of a unit measures thermal output leaving from the boiler, without subtracting thermal output returned to the boiler in boiler feedwater. See section VI, especially pp.65-70. Therefore, under the simplified approach, you do not assume an energy balance. Instead of measuring the thermal energy in the boiler feedwater return directly, one uses a generic value for a typical amount of thermal energy returning in condensate and incorporates this assumption into the factor used to calculate allocations from thermal output. As a result, the allocation factor for thermal output is smaller under the simplified approach than under the boiler efficiency approach. If you use thermal output data that are measured using the simplified approach, the thermal output values will be higher than under the boiler efficiency approach.

One could calculate a "pseudo-efficiency" by dividing the thermal output leaving the boiler and dividing it only by the heat input from fuel (and not including heat input from any hot water or steam entering the boiler). This "pseudo-efficiency" will be higher than the boiler efficiency described above.[6] Thus, the factor calculated based upon boiler efficiency using Equation 5 above

Limitations."

[6]The "pseudo-efficiency" can even exceed 100%.

will be too high.

Here are steps that we took to calculate an allocation factor for thermal output that incorporates energy in the boiler feedwater return. First, we assumed a typical actual heat input rate for an hour is 250 mmBtu/hr.[7] A boiler with an efficiency of 70% will actually transfer 175 mmBtu/hr to steam leaving the boiler. In most industrial and institutional applications, steam is saturated rather than superheated. Therefore, we assume saturated steam conditions and a typical enthalpy of roughly 1200 Btu per pound of steam leaving the boiler. With a boiler efficiency of 70%, steam leaving the boiler at 250 pounds per square inch (psi), and condensate in the boiler feedwater return at 150EF and with an enthalpy of 119.2 Btu/lb, we would find a steam flow of roughly 161,600 lb/hr.[8] With a steam flow of 161,600 lb/hr and an enthalpy of 1202.1 Btu/lb, the steam leaving the boiler has a thermal energy rate of 194.3 mmBtu/hr.

Now, we compare this to the allocation factor based on heat input and the heat input rate. The input-based factor is 0.17 lb NOx/mmBtu and the heat input rate is 250 mmBtu/hr. We can calculate the output-based factor in proportion:

$$\left(\frac{\text{output - based factor, lb / mmBtu output}}{0.17\ \text{lb / mmBtu input}}\right) = \left(\frac{250\ \text{mmBtu input / hr}}{194.3\ \text{mmBtu / hr output}}\right)$$

Calculation #1

[7] The Coalition for Gas-Based Environmental Solutions provided this assumption in a February 18, 2000 memorandum. We believe this is reasonable. We determined that the most common design heat input rate for a non-electric generating unit in the NOx SIP call region is 422 mmBtu/hr (both the median and mode value). The mean design heat input rate for a non-electric generating unit in the NOx SIP call region is 507 mmBtu/hr. Given these typical values for the design heat input rate of non-electric generating units, and assuming that industrial boilers typically run at 50 to 60 percent of their design capacity, a heat input rate of 250 mmBtu/hr is reasonable.

[8] These assumptions and calculations are provided in a February 18, 2000 memorandum from the Coalition for Gas-Based Environmental Solutions.

Using this calculation, we find that the allocation factor for thermal output is 0.22 lb NOx/ mmBtu output where the typical boiler efficiency is 70 percent.

If you wish to, you may calculate your own factor for thermal output under the simplified approach using the same general approach. For higher heat input rates, the steam flow rate would increase in proportion, as would the energy flow rate in the steam exiting the boiler. The factor will vary somewhat based upon the efficiency of the boiler in transferring heat to the steam or water leaving the boiler. You can use this table to determine the allocation factor using an assumed boiler efficiency, based upon the approach described in the previous two paragraphs:

Table II-1: Allocation Factor for Thermal Output by the Simplified Approach, Based on Boiler Efficiency

Assumed Typical Boiler Efficiency	Allocation Factor for Thermal Output Measured by the Simplified Approach
85%	0.18
80%	0.19
75%	0.20
70%	0.22
65%	0.24
60%	0.26
55%	0.28

≤ Other ways to determine a factor for thermal output

Alternatively, you may calculate the factor for thermal output by dividing the emissions budget for the non-electric generating unit sector in your State by the total thermal output from all affected non-electric generating units for an ozone season during some baseline period, if you know these numbers. This would require that sources continue to use the same monitoring approach for thermal output that they used historically and that is reflected in the thermal output data that you use in the calculation.

Representatives of the forest and paper products industry have stated that boilers tend to be less efficient when they combust biomass fuels, such as wood products, instead of fossil fuel. Thus, these boilers could be at a disadvantage in an output-based allocation system. This effect will be greater as the amount of non-fossil fuel burned by the boiler increases. The forest and paper products industry has claimed that there may be environmental benefits to using biomass fuels, such as a reduction in carbon dioxide emissions[9] and a reduction in solid waste that otherwise might be buried in a landfill[10], depending on the situation. We have not evaluated these claims and issues.

≤ Other notes on derivation of the allocation factors

The exact value of the factor does not matter, if all allocations in a group are calculated using the same factor, as in the model trading rule for the NOx SIP Call. Because there will be some sources that produce both thermal and electric output in both the EGU and non-EGU sectors, it will be more fair to treat the two forms of output as consistently as possible.

Note that the assumptions about the efficiencies of industrial boilers and electrical generation are not the same. Electric generation is inherently more difficult to produce and less efficient compared to the original heat input of fuel because of the steps needed to create the commercial product. For a utility boiler, this would include running steam through the steam turbine and generator. Industrial boilers measure their thermal output, which is an intermediate step in the process of creating the final commercial product (paper, chemicals, refined oil, etc.). It would not be appropriate to compute allocations assuming the same efficiency for an industrial boiler and for electric generation, because they operate through different processes with different thermodynamic properties and create different products that generally are not interchangeable. Thus, industrial boilers are inherently more capable of producing lower emissions for a given amount of energy coming out of the process than electric generators. This would not necessarily be the case once one included the inefficiencies involved in converting steam to a sellable product. Thus, we think it is appropriate to assume a typical operating efficiency for common technologies used in generating electricity and steam. We assumed an efficiency of roughly 34% (10,000 Btu/kWh) for electric

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[9] January 12, 2000 Comments of the American Forest & Paper Association Regarding the U.S. EPA's Draft Guidance on Output-Based Allocations for States Joining the NOx Budget Trading Program under the NOx SIP Call

[10] Presentation by William Nicholson, Potlatch Corporation. See minutes of March 25, 1999 Meeting of the Updating Output Emission Limitation Workgroup.

generation and assuming an efficiency of roughly 70% for steam generation by an industrial boiler.

Throughout the rest of this document, we will use a factor of 0.24 $lb/mmBtu_{out}$ for thermal output. This value assumes that sources determine their thermal output using the boiler efficiency approach. However, if you require sources in your state to monitor thermal output using the simplified approach, then you should use a factor of 0.22 $lb/mmBtu_{out}$.

Other forms of output:

You should not need other forms of output, unless you bring in additional categories of sources into the trading program that were not included in 40 CFR part 96. Note that this may extend the review time of your SIP and may even mean that we will not include you in the interstate NOx Budget Trading Program administered by EPA under the NOx SIP call. Other forms of output could include tons of clinker from cement kilns, or mechanical output in horsepower-hours from machines such as gas compressors or stationary internal combustion engines.

If you were to calculate NOx allowance allocations for other forms of output, you would use a similar equation with a factor in lb NOx per unit of output, multiplied by the output during the baseline period, divided by 2000 lb/ton. Ideally, the factor should be similar to the target average NOx emission rate for that form of output. This could be calculated by the emissions budget for the sector in your State divided by the output for affected sources in that sector during the ozone season of a baseline period. Again, as long as this other category of sources has a sector budget and as long as this category produces only one kind of output, the size of the factor does not matter, and in fact, is not truly necessary. You would still need to define the form of output from the process and establish a procedure to determine the output.

B. How do I calculate the unadjusted allocation for each source?

Use the emission rate factor based on output (e.g., 1.5 lb/MWh or 0.24 $lb/mmBtu_{out}$). Multiply this emission rate by the output during the ozone season in the baseline period you choose.

For electric output

Multiply 1.5 lb/MWh by the electric output during the ozone season in the baseline period you choose. An example of electric output during a baseline period is the average generation from the two highest ozone seasons of electric generation from the years 1995, 1996, and 1997. Divide this number of pounds of NOx by 2000 to calculate the source's unadjusted allocation in tons.

Example. Calculation of unadjusted allocation using electric generation

Unit 1 at the Deep River Generating Station generated 2,287,047 MWh in May 1 through September 30 of 1995, 2,955,019 MWh in May 1 through September 30 of 1996, and 2,633,547 MWh in May 1 through September 30 of 1997. The average generation during the ozone season for the two highest of the three years is 2,794,283 MWh. Calculate the unadjusted allocation for Unit 1 as follows:

$$\text{Allocation} = \left(\frac{1.5 \text{ lb } NO_x}{\text{MWh}}\right)\left[\frac{2{,}794{,}283 \text{ MWh}}{2000 \text{ lb / ton}}\right]$$

Finally, round up the allocation to the nearest whole ton, for an unadjusted allocation of 2096 allowances.

For thermal output

The same general approach applies for calculating an allocation based on thermal output. Multiply the emission standard of 0.24 (or 0.22) lb/mmBtu$_{out}$ by the thermal output in mmBtu$_{out}$ during the baseline period you choose. Then divide this value by 2000 lb/ton. Generally, round up fractional tons of 0.5 or greater, or round down fractional tons of less than 0.5 to calculate the allocation to the nearest whole ton.

C. How do I develop unadjusted output-based allocations for sources that produce more than one form of output (such as, both electricity and steam)?

Allocate NOx allowances to the unit by each type of energy, rather than once for the type of facility. Add the initial tonnages for each form of output to get a total unadjusted allocation. For example, for an electric generating unit that is a combined heat and power project, you will calculate one tonnage value for the electric output and a second tonnage value for the thermal output. Add the tonnages before rounding. Generally, round the total tonnage to the nearest whole ton to get the unadjusted allocation for the unit.

Example. Calculation by energy type.

Unit 2 at the Rocky Valley Cogeneration Facility produces both electricity and steam. The State receives its historic electricity and steam generation for May 1 through September 30 of 1995, 1996, and 1997. The State then drops the lowest electric output value out of the three control periods and the lowest thermal output value out of the three control periods. For electric output, the State uses the average electric output from 1995 and 1997. For thermal output, the State uses the average thermal output from 1995 and 1996. The electric output and the thermal output values that the State uses to calculate raw allocations are as follows:

Electric and Thermal Output at Rocky Valley Cogeneration Facility Unit 2

Electric output (MWh)	Thermal output ($mmBtu_{out}$)
11,193	191,008

Unit 2's allocation portion based on electric output is calculated as:

$$Electric\,Output\,tonnage = \left(1.5\,\frac{lb}{MWh}\right)\left[11{,}193\,MWh\right] \Big/ 2000\,lb/ton \;=\; 8.4\,tons$$

Unit 2's allocation portion based on thermal output is calculated as:

$$Thermal\,Output\,tonnage = \frac{\left(0.24\,\dfrac{lb}{mmBtu_{out}}\right)\left[191{,}008\,mmBtu_{out}\right]}{2000\,lb/ton} = 22.9\,tons$$

The total tonnage for the unit then equals 8.4 + 22.9 = 31.3 tons. Unit 2's unadjusted allocation is 31 allowances.

It is also possible to "convert" thermal energy to electric output. However, this is not necessary, as shown by the example above. Any conversion will require assumptions that depend upon the technology being used.

D. How do I adjust the unadjusted allocations to fit my State budget?

There are a number of approaches you can use. In this section, we will describe an approach that assumes that both electric generating units (EGUs) and industrial and institutional turbines and boilers (non-electric generating units, or "non-EGUs") receive NOx allowance allocations based on output. Under this approach, you would keep separate "sector" budgets for electric generating units and for non-EGUs. Then the total NOx allowances allocated to all sources within each sector must be equal to the sector budgets for each facility type. If you include electric generating systems that are not fossil fuel-fired (e.g., non-emitting electric generating systems), you would count allowances for those generating systems against the electric generating unit sector budget.

Under this approach, you would:

1. Add up all unadjusted allocations for an entire sector.
2. Divide the unadjusted allocation for each unit (or non-emitting generating system) in the sector by the total unadjusted allocations for the sector.
3. Multiply that fraction times the sector budget.

Example. Adjusting allocations in a sector budget; each sector using both thermal and electric output

The State of Columbia has an EGU sector budget of 2722 tons and a non-EGU sector budget of 278 tons. The total State budget for sources in the trading program is 3000 tons. This State does not have any set-asides for new units or energy efficiency and renewable energy. The State has the following sources with the following unadjusted allocations:

Table II-2: Unadjusted NOx Allowance Allocations and Supporting Output Data for the EGU Sector

Name of electric generating unit	Baseline electric output (MWh)	Baseline thermal output ($mmBtu_{out}$)	Unadjusted allocation (tons)
Deep River Unit 1	1,506,278		1130
Deep River Unit 2	400,916		301
Megawatt Station GT-1	147,982		111
Central Power Unit 1	605,739		455
Central Power Unit 2	971,545		729
Journeytown Cogen CT-1	120,013	601,956	162
EGU Sector total:			2888

Table II-3: Unadjusted NOx Allowance Allocations and Supporting Output Data for the Non-EGU Sector

Name of non-electric generating unit	Baseline thermal output ($mmBtu_{out}$)	Baseline electric output (MWh)	Unadjusted allocation (tons)
Chemical Plant Unit 1	1,286,576		154
Columbia Paper Boiler 1	283,400	16,607	46
Petro Oil Unit 1	708,037		85
Non-EGU Sector total:			285

There will be some differences in individual unit allocations introduced by changing the unit allocations from a heat input basis to an output basis. These changes will vary depending on how efficient a particular unit is.

The electric generating unit allocations add up together to 2885 allowances. However, the EGU sector budget is only 2722 tons. Each electric generating unit's allocation will need to be adjusted downward in proportion to each unit's share of the total allowances. For example, you would calculate the adjusted allocation for Journeytown Cogen CT-1 this way:

$$\text{Adjusted Allocation} = \left[\frac{\text{Unadjusted Allocation for Unit / Generator}}{\text{Sector Unadjusted Allocation Total}}\right](\text{Sector Budget}) =$$

$$\left(\frac{162 \text{ tons}}{2888 \text{ tons}}\right)[2722 \text{ tons}] = 153 \text{ tons}$$

The next table shows the unadjusted and adjusted NOx allowance allocations in the electric generating sector using this same calculation:

Table II-4: NOx Allowance Allocations for the EGU Sector, Adjusted by Sector

Name of electric generating unit	Unadjusted allocation (tons)	Adjusted allocation (tons)
Deep River Unit 1	1130	1064
Deep River Unit 2	301	284
Megawatt Station GT-1	111	105
Central Power Unit 1	455	429
Central Power Unit 2	729	687
Journeytown Cogen CT-1	162	153
EGU Sector total:	2888	2722

In calculating adjusted allocations, tonnages are rounded up or down to the whole allowance. Generally, a fractional tonnage that is 0.5 or higher is rounded up; a fraction ton that is less than 0.5 is rounded down. However, the rounding must be done in a way that ensures that the total of the adjusted allocations equals the sector total. This means that you may not always follow the general rule for rounding.

You can do similar calculations to determine the adjusted allocations for the units in the non-EGU sector. Note that in this sector, the unadjusted total allocation for the sector is less than the non-EGU sector budget; adjusting the allocations gives each source a larger adjusted allocation than unadjusted allocation. Here is the example calculation for Petro Oil Unit 1:

$$\text{Adjusted Allocation} = \left(\frac{85\text{ tons}}{285\text{ tons}}\right)[278\text{ tons}] = 83\text{ tons}$$

Here are the unadjusted and adjusted NOx allowance allocations in the non-EGU sector:

Table II-5: NOx Allowance Allocations for the Non-EGU Sector, Adjusted by Sector

Name of non-electric generating unit	Unadjusted allocation (tons)	Adjusted allocation (tons)
Chemical Plant Unit 1	154	150
Columbia Paper Boiler 1	46	45
Petro Oil Unit 1	85	83
Non-EGU Sector total:	285	278

Note that in the example, if the State of Columbia had a 2% new source set-aside, then the number of allowances for allocations would be 2% less. In that case, the number of allowances to go to the EGU sector would add up to 2668 tons (98% of 2722, rounded up) and the number of allowances for the non-EGU sector would add up to 272 tons (98% of 278 rounded down). In the formula above, these smaller tonnage values would be used as the "Sector Budget" when calculating the adjusted allowance allocations.

There is sample rule language to support this approach in Cases 2 and 4 of Appendix A to this document. Case 2 assumes an initial allocation based upon heat input for both EGUs and non-EGUs with updated allocations based upon output. Case 4 assumes both initial and updated allocations based upon output for both EGUs and non-EGUs. Both of these cases assume that allocations are adjusted separately to fit each sector's budget.

Comparison of allocations under different approaches

Another possible approach to adjusting NOx allowance allocations would be to allocate NOx allowances to each unit (or non-emitting generating system), and then you would adjust the total

NOx allowances allocated to all trading sources within the State so that they equal the State trading budget. Under this approach, you would:

1. Add up all unadjusted allocations for sources in the trading program.
2. Divide the unadjusted allocation for each unit (or non-emitting generating system) in the sector by the total unadjusted allocations in the trading program.
3. Multiply that fraction times the trading program budget.

We chose not to implement this approach to NOx allowance allocations in EPA's section 126 rulemaking. We concluded that adjusting allocations within the sector budgets was consistent with the original levels of emission control that we selected for each sector:

(1) An average NOx emission rate of 0.15 lb/mmBtu for EGUs and

(2) An average NOx reduction of 60% for non-EGUs, corresponding to an average NOx emission rate of 0.17 lb/mmBtu.

In contrast, we found that allowances would move from the non-EGU sector to the EGU sector under an approach where unadjusted allocations are adjusted to fit the entire trading budget. This means that non-EGUs receive allocations based on a stricter standard than originally selected, while EGUs receive allocations at a slightly less stringent standard.

Here is a summary of the final adjusted allocations for each unit under the two different approaches for allocation adjustment: adjustment by source sector and adjustment to the entire trading budget.

Table II-6: NOx Allowance Allocations for Trading Sources in Columbia, by Method for Adjustment

Name of source	Adjusted allocation, adjusted by source sector (tons)	Adjusted allocation, adjusted for the entire trading budget (tons)
Electric generating units		
Deep River Unit 1	1064	1069
Deep River Unit 2	284	285
Megawatt Station GT-1	105	105
Central Power Unit 1	429	430
Central Power Unit 2	687	689
Journeytown Cogen CT-1	153	153
EGU Sector subtotal:	2722	2731
Non-electric generating units		
Chemical Plant Unit 1	150	146
Columbia Paper Boiler 1	45	43
Petro Oil Unit 1	83	80
Non-EGU Sector subtotal:	278	269
Trading Budget total:	3000	3000

You may also want to compare these output-based allocations to the allocations calculated in the next section, "How should I set up allocations if I choose to allocate to some sources based on output and to other sources based on heat input?" (pp. 40-43). In that section, the electric generating units receive allocations based on output, while the non-electric generating units receive allocations based on heat input. That section also considers adjusting allocations by sector and for the entire trading budget. A major difference between the heat input-based allocation and the output-based allocation for non-electric generating units is that the cogeneration facility Columbia Paper Boiler 1 receives higher allocations under an output-based approach. This reflects the cogeneration unit's greater efficiency.

E. How should I set up allocations if I choose to allocate to some sources based on output and to other sources based on heat input?

You can keep separate sector budgets for sources receiving allocations based on heat input and a separate sector budget for sources receiving allocations based on output. Then the total NOx allowances allocated to all sources within each sector must be equal to the sector budget. This approach may be appropriate if you allocate allowances to electric generating units based on output, and to non-electric generating units based on heat input. It is also possible to have a few individual units within a sector receiving unadjusted allocations based on heat input, while other units receive unadjusted allocations based upon output. This approach may be appropriate if you have a few individual units that cannot be monitored for output, but most units in the State can be monitored for output. EPA believes that all electric generating units should be able to monitor their output. In addition, all non-electric generating units can measure their heat input.

Unadjusted allocation of allowances using heat input

For a non-electric generating unit, the formula for calculating an unadjusted allocation using heat input is:

$$\text{Unadjusted Allocation} = \left(\frac{0.17\ \text{lb}\ \text{NO}_X}{\text{mmBtu}_{\text{Heat input}}}\right)\left[\frac{\begin{array}{l}\text{Heat input (fuel usage) used during}\\ \text{baseline period, in mmBtu}\end{array}}{2000\ \text{lb / ton}}\right] \qquad \text{Eq. 6}$$

In general, you will round the allocation up or down to the nearest whole ton.

Fitting unadjusted allocations to a sector budget

To adjust the allocations, you would:

1. Add up all unadjusted allocations for an entire sector.
2. Divide the unadjusted allocation for each unit (or non-emitting generating system) in the sector by the total unadjusted allocations for the sector.
3. Determine the fraction of the total number of allowances for each unit (or non-emitting

generating system) in the sector, and then multiply that fraction times the sector budget.

Example. Adjusting allocations in a sector budget; one sector using heat input, another using output

The State of Columbia has an EGU sector budget of 2,722 tons and a non-EGU sector budget of 278 tons. The total State budget for sources in the trading program is 3000 tons. This State does not have any set-asides for new units or energy efficiency and renewable energy. Columbia has the same EGUs with the same electric output as described in the previous section II.D., "How do I adjust the unadjusted allocations to fit my State budget?" (pp. 34-40).

The electric generating unit allocations add up together to 2880 allowances. However, the EGU sector budget is only 2722 tons. Each electric generating unit's allocation will need to be adjusted downward in proportion to each unit's share of the total allowances going to electric generating units, as described in the first example in the previous section II.D. (pp. 34-40)

The non-EGUs in Columbia have the following unadjusted allocations and heat input data:

Table II-7: Unadjusted NOx Allowance Allocations and Supporting Heat Input Data for the Non-EGU Sector

Name of Non-electric Generating Unit	Baseline Heat Input (mmBtu heat input)	Unadjusted Allocation (tons)
Chemical Plant Unit 1	1,715,435	146
Columbia Paper Boiler 1	400,094	34
Petro Oil Unit 1	874,120	75
Non-EGU Sector total:		255

You can do calculations to determine the adjusted allocations for the units in the non-EGU sector. Note that in this sector, the unadjusted total allocation for the sector is less than the non-EGU sector budget; adjusting the allocations gives each source a larger adjusted allocation than the original unadjusted allocation. Here is the example calculation for Petro Oil Unit 1:

$$\text{Adjusted Allocation} = \left(\frac{75\text{ tons}}{255\text{ tons}}\right)[278\text{ tons}] = 82\text{ tons}$$

Calculation #7

Here are the unadjusted and adjusted NOx allowance allocations in the non-EGU sector:

Table II-8: NOx Allowance Allocations for the Non-EGU Sector Based on Heat Input

Name of Non-electric generating unit	Unadjusted Allocation (tons)	Adjusted Allocation (tons)
Chemical Plant Unit 1	146	159
Columbia Paper Boiler 1	34	37
Petro Oil Unit 1	75	82
Non-EGU Sector total:	255	278

There is sample rule language to support this approach in Cases 1 and 3 of Appendix A to this document. Case 1 assumes an initial allocation based upon heat input for both EGUs and non-EGUs with updated allocations based upon output for EGUs and based upon heat input for non-EGUs. Case 3 assumes both initial and updated allocations based upon output EGUs and based upon heat input for non-EGUs. Both of these cases assume that allocations are adjusted separately for each sector's budget.

Allocation to individual sources based upon heat input

You also could calculate an allocation based upon heat input for one or more individual units in a sector (or in the entire trading budget) while the rest of the sources receive an allocation based upon output. You would use the factor of 0.17 lb/mmBtu input times the baseline heat input for those individual sources to calculate their unadjusted allocation. Other sources would have their unadjusted allocations calculated based upon the factors of 1.5 lb/MWh times baseline electric generation and 0.24 lb/mmBtu[11] output times baseline thermal output. You would then adjust these unadjusted allocations to fit the size of each sector. However, if you do not treat all sources the same, you and companies in your State may be concerned about equity. You do not want a situation

[11] This factor assumes that sources monitor thermal output using the boiler efficiency approach, as described in section VI (pp. 68-69, 84-91, and 124-137). If you require sources to monitor thermal output using the simplified approach, instead use the factor 0.22 lb/mmBtu output for thermal output.

where relative inefficient sources may receive their allocations based upon heat input, while relatively efficient sources receive their allocations based upon output. Therefore, you may want to consider this source-by-source approach only as a last resort for cases where you judge that output monitoring is unduly expensive for a particularly complicated source.

III. Applicability: For which kinds of facilities does this guidance help me develop output-based allocations?

This guidance will assist you in developing and updating output-based allocations from the core source categories included in the model NOx trading rule under the NOx SIP call:

- fossil fuel-fired electric generating units serving a generator greater than 25 MWe, and
- fossil fuel-fired non-electric generating units (industrial or institutional boilers and turbines) with a design heat input greater than 250 mmBtu/hr.

If you join the NOx Budget Trading Program under the NOx SIP call, you will be controlling NOx emissions from these categories of units. You also may choose to include other facilities in your State's NOx Budget Trading Program. Note that if you allocate allowances to sources other than fossil fuel-fired electric generating units, non-emitting electric generating systems, or fossil-fuel fired non-electric generating units, this may extend the review time of your SIP. This is because there may be monitoring and applicability issues that need to be resolved before we can administer a trading program for other types of facilities.

This guidance will allow you to develop output-based allocations and update them for the following types of facilities:

< Fossil fuel-fired electric generating units.

< Non-emitting electric generating systems. This includes nuclear power plants, hydroelectric plants, wind power plants, geothermal power plants, and power plants using most other renewable energy resources.

< Non-fossil fuel-fired boilers (both electric generating and non-electric generating).

< Most industrial or institutional boilers and turbines that produce steam or hot water as their forms of thermal output.

< Cogeneration facilities that produce steam or hot water and electricity in sequence.

This guidance will not help you if you decide to allocate NOx allowances to facilities that produce output in forms other than electricity, steam, or hot water. For example, this would include:

< Industrial boilers that use hot exhaust gases to dry a manufacturing product, such as paper.

< Process heaters where hot exhaust gases are used to heat materials as part of the manufacturing process. Cement kilns, glass manufacturing, chemical production, and

production of iron, steel, or other metals may fall into this category.

< Industrial sources that produce mechanical work, such as gas compressors or internal combustion engines.

< Nitric acid plants.

Quantification of output from these sources may be very dependent upon the individual process and could require a case-by-case procedure for determining output.

You may, but do not need to, allocate NOx allowances based on output to all facilities in the NOx Budget Trading Program in your state. For example, you could issue NOx allowance allocations to fossil fuel-fired electric generating units based on output and issue allocations to fossil fuel-fired non-electric generating units based on heat input (that is, fuel usage, in mmBtu). You may find it is useful to have the flexibility to issue allocations on a different basis for different kinds of facilities.

IV. Level of Allocations: Should I allocate to units, to generators, or to entire facilities?

In theory, any of these approaches are possible. However, there are practical reasons for choosing to allocate NOx allowances to units or to entire facilities. For administrative reasons, we believe it may be simplest to allocate NOx allowances to units. Also take a look at section V of this guidance document, "Where should sources determine output to be used for allocations?" as you consider this issue (pp. 49-54).

In this discussion and throughout this document, a unit is an individual combustion device such as an individual boiler or combustion turbine. A facility is a plant. A facility may have more than one unit, more than one generator, or more than one configuration of units and generators that are connected. In many cases, there is one and only one unit for each electric generator, but there are also other configurations that are more complicated.

A. When is it appropriate to allocate to units?

In general, we think it is simplest to allocate NOx allowances to units for administrative purposes. In particular, we suggest that you allocate NOx allowances to units and not to entire facilities or generators if you choose to allocate based upon gross output. For non-electric generating units, gross output can be measured for each unit. For electric generating units, the gross electric output is actually measured from the generator rather than the attached unit (boiler or turbine). However, for units in existing cap and trade programs, our NOx Allowance Tracking System has allowance accounts for units and plants, but not for generators. Therefore, we believe it would cause unnecessary administrative work, expense, and potential confusion to create new accounts for generators. If you were to calculate allocations using data from generators, you still would need to send allocations to EPA that are assigned to units or entire plants.

In a few cases, more than one unit (boiler or turbine) may serve a single generator or a single unit may serve more than one generator. In this situation, we recommend that you or the owners or operators of the units find a simple way to apportion generation from all of the generators to all of their associated units. One simple approach would be to divide the total generation by the number of hours that each unit combusted fuel, or by the number of operating hours times the nameplate capacity of each unit. Another simple way would be to apportion the allowances based on the heat input combusted by each unit.

B. When is it appropriate to allocate to entire facilities?

You may want to allocate NOx allowances to an entire facility if you choose to allocate based upon net output. In general, power plants keep track of the net electric output leaving the plant. Some power plants measure net output either directly from the entire plant or from individual units. Other plants calculate the net electric output for the entire plant but do not measure the net output directly and do not determine the net output from individual units.

EPA has concluded that it is possible to keep plant level allowance accounts. These are currently built into the NOx Allowance Tracking System as "overdraft" accounts. Therefore, it is possible for a State to specify that all allowance allocations for a facility go into an account for the entire facility. However, each *unit* must still comply, and EPA will determine compliance at the unit level. Therefore, the owners and operators of the facility will be responsible for distributing allowances among the unit compliance accounts. Based on our experience implementing the OTC NOx Budget Program, we found that some sources made errors in distributing their allowances to their compliance accounts. Thus, we believe it would be simpler for sources and for EPA's administration if you initially allocate NOx allowances to units, rather than to facilities.

In addition, if you calculate plant level accounts, there may be some situations where one unit at a facility is not in the NOx Budget Trading Program under the NOx SIP call while another unit is. In this case, it will be necessary to subtract the output from the unit that is not in the program from the total plant output in order to obtain the output for the units in the program.

You may want to consider whether the companies in your State have concerns about unit ownership before allocating NOx allowances at the plant level. In some cases the same plant will have different owners of different units. An owner of one unit may not have say in how the unit is operated if another owner or operator controls the units at the plant. It is also possible to have ownership conflicts concerning a unit if there are multiple owners, so allocating at the unit level may not necessarily avoid all potential ownership conflicts. However, in many cases, all units at a plant have the same owner, and this is not an issue.

C. When is it appropriate to allocate to generators?

We suggest that you allocate NOx allowances to generators only if you intend to allocate allowances to non-emitting electricity generating systems. This could include nuclear power plants, hydroelectric plants, wind power generators, geothermal generators, or other generators of electricity that do not emit NOx. If you include in your trading program boilers or turbines that emit NOx but that are not fossil fuel-fired, you should treat them as NOx Budget units subject to all requirements under the trading program (including compliance).

V. Where should sources determine output to be used for allocations?

A. Why does it matter where sources measure their output?

The major policy reason for using output-based emission limitations is to encourage producing useful products for sale while creating less emissions. This also encourages efficiency, in an environmental sense. Depending on where one measures or calculates output in a process, the output value will be farther from or closer to linking emissions to the useful product made by the process. Different locations for determining output have different implications for monitoring and reporting of output data and for the kinds of incentives sources will receive.

Some State environmental agencies have shown interest in allocations based upon net output because, theoretically, they would encourage sources to create the same useful output more efficiently and with less pollution. For example, the Massachusetts Department of Environmental Protection has stated:

> *An important goal of the output-based allocation is to minimize the resources necessary to produce a unit of useful output. In the case of electricity generation, this requires maximizing the efficiency of plant generation and minimizing the energy required for plant use and pollution control, since the useful output of an electricity generator is the unit of electricity that enters the wholesale electricity market....* (January 12, 2000 Comments on EPA's Draft Guidance for States Joining the NOx Budget Trading Program under the NOx SIP Call)

In principle, to create the closest link between emissions and useful products for sale, companies would measure or determine the product that they sell as their output. For example, the owner of a power plant would measure the electricity that the owner sells to the interstate electric grid. The amount of electricity that the company sells does *not* include power used inside the plant[12] or power losses, such as:

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[12]For a power plant, typically three to six percent of the gross output from the generator terminals is used internally, depending on the emission controls used at the unit. Auxiliaries and pollution control equipment could consume as much as twelve percent of gross output. Information provided in “Measurement Of Net Versus Gross Power Generation For The Allocation Of NOx Emission Allowances,” January 27, 1999, paper by FirstEnergy Corp.

- Auxiliaries loads related to electric generation, such as fuel handling and preparation equipment, pumps, compressors, motors, and fans
- Load used to operate pollution control devices
- House loads (loads used inside the plant to operate the building, such as electricity used to light the plant or to run office equipment inside the building)
- Energy lost by the boiler or steam turbine as electricity is generated

Therefore, the location for determining output that would seem to link the useful electricity sold to the emissions produced as directly as possible would be at the connection where power is transmitted and sold from the plant to the grid (net electric output). A boiler at the power plant could combust the same amount of fuel and produce the same amount of emissions while increasing the amount of electricity sold if the company can reduce the amount of power used inside the plant.

Electric output measurements do not need to account for:

- Line losses
- End use efficiency outside the plant

Although these losses ultimately have an impact upon emissions, the company probably has little or no control over these factors outside the plant. Therefore, we focus on controlling the source of the emissions–the boiler or turbine combusting fuel.

In the case of industrial boilers, a boiler makes an intermediate product, steam or hot water, that then is used in making the final product. There are a large number of industrial processes and products. In this document, we simplify measuring output from industrial boilers by measuring the thermal output of the steam or hot water from the boiler. In some cases, steam from a boiler is sold commercially. However, more often, the thermal output is a proxy for the final product for sale, whether it is paper, chemicals, or refined oil.

Keep in mind that the ultimate purpose of an output-based emission limitation for an industrial boiler should be to encourage making products with less pollution. Thus, you are not simply trying to encourage boiler (energy) efficiency, but encouraging the environmental efficiency of producing thermal output which is then used to make a final product for sale. Industrial boilers also have losses (waste heat) and heat used inside the plant for purposes that do not produce the final product being sold. These include:

- Auxiliaries thermal loads related to thermal energy generation, such as pumps or compressors
- Thermal output used for air or feedwater preheating
- House loads (heat used inside the steam house to operate the building and to generate thermal energy)
- Energy lost from the boiler or from pipes carrying steam or water

Ideally, a company would measure the thermal output after all these are removed, at the point that steam or hot water is used to make the final product.

In some cases, plants do not directly measure the net output used in creating a product. Instead, they might determine the net output by:

1. First, measuring the gross electric output at the generator terminals or the gross thermal output coming directly from the boiler header.
2. Then, measuring power or steam or hot water used inside the plant for auxiliaries, pollution control devices, thermal recover, house loads, or any other use that does not actually produce the product generated for sale.
3. Finally, subtract all the power or steam or hot water listed under number 2 above from the gross output listed under number 1 above.

Also, in some cases, it is much easier to calculate the electricity or thermal energy at a point inside the plant instead of directly measuring it. For example, a company may choose to calculate thermal energy in a high-pressure steam pipe rather than opening it in order to install measurement equipment.

For companies receiving NOx allowance allocations, the location where they determine output that you will use for allocations matters because the location affects the size of the output value and therefore, the size of their allocation. In addition, the location where they determine output may have existing monitoring equipment or may require new monitoring equipment, and thus cause greater or less expense in monitoring output.

B. What are factors I should consider before deciding on the location where sources determine output?

Although the State environmental agencies we have worked with have expressed interest in using net output as the basis for allocations, you may choose a different approach. Here are some addition factors you may want to consider as you make your decision.

Monitoring considerations

In some cases, it can be difficult to measure or even to calculate net output without adding a significant, and expensive, amount of monitoring equipment. For example, if a series of boilers is connected to several interconnected steam headers with a number of pipes taking off steam for use both as house loads and for making the end product, the company will have an extremely complicated monitoring situation. For many old industrial boilers, it may be much easier for companies to measure the gross thermal output coming straight from the boiler. In addition, it is likely that industrial boiler owners already measure the gross thermal output, but it is less likely that they determine the net thermal output.

As a rule, power plants determine both their gross and their net electric output. They do not necessarily measure both directly.

Gross output does not take into account factors of unit efficiency related to operating auxiliary equipment and pollution control equipment. However, gross and net output both take into account some factors of unit efficiency, such as: age of the unit; type of unit; operating practices and conditions; capacity factor; and the need to follow customer demand for electric generation. Thus, allocations based upon gross output still provides some incentive for improving efficiency, compared to allocations based upon heat input.

Power companies generally measure gross electric output from each electric generator. For most plants, there is one and only one generator for each unit, so usually you can link gross output measurements to a unit. However, there are some cases where there are multiple units (boilers) associated with a single generator, or a unit associated with more than one generator. This may have an impact on how you decide to allocate allowances.

Net electric output may be measured either for an entire plant or for individual generators, depending on the facility. Some plants measure gross output and auxiliary usage and then calculate net output, rather than measuring net output directly.

For some conventional power plants, net electric output is more difficult to determine than gross electric output. For cogenerators, gross thermal output may be more difficult to measure than net thermal output because part of the steam is diverted to generate electricity.

Sources of output data

Some data sources provide only gross generation or only net generation, but not both. For example, the electric generation data that utilities report to EPA currently are only gross electric output data. The electric generation data the utilities report to the Energy Information Agency (EIA) on form 759 are net electric output data. Thus, consider the data source you want to use at the same time that you decide whether to use gross or net output. (See section VIII., “Where do I get the data for an output-based allocation?”, pp. 163-166)

Encouraging specific NOx control strategies

Using net generation as a basis for allocations will tend to benefit facilities that burn cleaner fuels or that do not burn fuel at all. Net output, or output that excludes power used to operate pollution control equipment, may encourage pollution prevention more than gross output, or output that includes power going to pollution controls.

However, if you do not want to discourage sources from installing add-on pollution controls[13], you may want to include the power used to operate pollution control equipment as part of the calculation of output used in allocations. Consider an example where one coal fired-unit has a scrubber and a second coal-fired unit of similar size, type, and fuel usage does not have a scrubber. If the power used to operate the scrubber is not included in your calculation of output, the unit with no scrubber will receive a larger allocation. If the power used to operate the scrubber is included in your calculation of output, both units will receive the same size allocation.

C. How could I incorporate the concept of the location for determining output into my State rule?

You could describe whether you are basing allocations based on gross or net output. You also could use some variation of net or gross output that includes or excludes certain uses of power or steam within the plant. For example, you could define electric output to include power sold to the grid and power used to operate pollution control equipment. You also should define gross output

[13] The United Mine Workers of America have claimed that there can be significant social costs for policies that discourage retrofit controls and cause unemployment among coal miners. Minutes of the Updating Output Emission Limitations Workgroup, Thursday, March 25, 1999.

or net output. This will help ensure that all facilities are clear what information they need to report and will treat different facilities as equitably as possible. See section V.A., “Why does it matter where sources measure their output?” and the definitions in Appendix A for descriptions of net and gross output (pp. 49-51, 171-172).

You also will need to have consistent monitoring and reporting requirements. Also, see sections VI., “Where do facilities measure electric and thermal output?” and VII,”How should sources monitor, record, and report output data to support updating output-based allocations?” in this guidance document (pp. 55-141, 142-162).

VI: Monitoring locations: Where could facilities monitor electric and thermal output?

A. Where should output measurement equipment be installed?

This will depend on the type of output to be measure: gross or net; and electric or thermal. Monitoring for both plant and unit level output should be similar with the only difference being how the measured output is apportioned and reported. In addition, the locations for monitoring vary based on the type of facility.

Conventional power plants (non-cogeneration) will measure, and will receive allocations based on, electric output only. These conventional power plants will not need to measure any additional thermal energy for the purposes of supporting data for allocations, because conventional power plants use thermal energy to produce electricity, rather than for other useful purposes. Steam generators (industrial or institutional boilers and turbines that do not generate electricity) will measure, and will receive allocations based on, thermal output only. Steam generators will not need to measure any electric output for the purposes of supporting data for allocations.

Facilities that produce both electricity and steam or hot water as useful outputs will need to measure both thermal and electric output. Most of these are cogeneration facilities, also called combined heat and power (CHP) facilities. Cogeneration facilities tend to be more efficient because they produce thermal output and electric output in sequence, from the same heat input. In order to determine net output, facilities producing both kinds of output will need to account for parasitic and house loads for both electricity and steam or hot water. Cogeneration facilities can be classified either as electric generating units or as non-electric generating units, depending on the characteristics of the unit and the associated generator.

In section VI, we provide tables that describe which locations a source would monitor, depending on the type of output and the type of facility (pp. 58, 62, 73, 83, 96-101, and 118-123). The tables describe how to monitor both net and gross electric and thermal output. They also describe monitoring locations for conventional power plants where a company would measure only electric output; for steam generators where a company would measure only thermal output; and for cogeneration facilities where a facility would measure both thermal and electric output. In each case, we provide a "primary approach" for measuring a type of output. This is the approach that we understand sources are most likely to use. In addition, we provide alternative approaches in case you wish to provide extra flexibility that will allow sources to use existing equipment for monitoring output.

In addition, we provide six simplified diagrams that picture the points for measuring electricity and thermal energy at six different types of facilities you are likely to see in your State: a conventional power plant; a steam generator; a steam generator that has a line for reheating steam; a steam cogenerator; a combustion turbine cogenerator; and a combined cycle cogenerator with a secondary electric generator after the heat recovery steam generator. Keep in mind that in many real plants, there may be several places in a plant that are represented with a single point in the diagram. Thus, output monitoring for some plants may be more difficult and expensive that it appears from these simplified diagrams. However, the diagrams will help you understand the types of locations that a source may need to monitor for output.

In section VI.B., “How could sources monitor electric output only at a conventional electric power plant?” (pp. 60-67), we describe monitoring locations for electric output from conventional power plants (non-cogeneration). These are similar to the monitoring locations for electric output from cogeneration facilities, which are discussed below in section VI.D., “How could sources monitor electric and thermal output at a cogeneration facility?” (pp. 92-137).

In section VI.C., “How could sources monitor thermal output at a steam generator?” (pp. 68-91), we describe monitoring locations for thermal output only from industrial and institutional boilers (non-cogeneration). This section also describes two different approaches to monitoring thermal output: the **Simplified Approach** and the **Boiler Efficiency Approach**. The monitoring locations and possibly some equipment are different for thermal output under the two approaches. The boiler efficiency approach utilizes the traditional engineering approach to measuring thermal output where the thermal output is measured using an energy balance around the boiler or system to determine the energy transferred to the steam from combustion. The simplified approach measures thermal output in a single location, using a generic value for the energy returning to the boiler or system in boiler feedwater return or make up water as part of the allocation factor, rather than requiring measurement of the boiler feedwater return or make up water. This section explains how to monitor thermal output using the two approaches and explains why you might prefer one approach over the other.

In section VI.D., "How could sources monitor electric and thermal output at a cogeneration facility?" (pp. 92-137), we describe how to monitor both electric and thermal output from three common types of cogeneration facilities: steam cogenerators, combustion turbine cogenerators, and combined cycle systems. We describe how to monitor thermal output under both the simplified approach and the boiler efficiency approach.

Table VI-1 summarizes the most common approaches to monitoring output (pp. 58-59). The most common approaches and alternative approaches are discussed below in detail in sections VI.B, VI.C., and VI.D.

Table VI-1: Summary of Most Common Approaches to Monitoring Output

If you look at this facility type	and you require this type of output to be used for allocations	there are more details here	and this is the most common approach to monitoring output
Conventional power plant (Figure 1, p. 61)	net electric	VI.B.1 (pp. 63-65)	Measure electric power sold and power used in a useful process, less any incoming electricity provided to the plant during operation of the generator
	gross electric	VI.B.2 (pp. 65-66)	Measure electric power at the generator terminals
Steam generator (Figures 2 and 3, pp. 71, 81, 72, 82)	net thermal (by simplified approach)	VI.C.1 (pp. 74-76)	Measure thermal energy sold and thermal energy going into a useful process
	gross thermal (by simplified approach)	VI.C.2 (pp. 76-78)	Measure thermal energy leaving the boiler
	net thermal (by boiler efficiency approach)	VI.C.3 (pp. 84-86)	Measure thermal energy sold and thermal energy going into a useful process, less any thermal energy returned to boiler in boiler feedwater, make up water, or steam return for reheating
	gross thermal (by boiler efficiency approach)	VI.C.4 (pp. 87-89)	Measure thermal energy leaving the boiler, less any thermal energy returned to boiler in boiler feedwater, make up water, or steam return for reheating
Steam cogenerator with process use of steam downstream of the steam turbine (Figure 4, pp. 93, 115)	net electric	VI.D.1.a and VI.B.1 (pp. 63-65, 102)	Measure electric power sold and power used in a useful process, less any incoming electricity provided to the plant during operation of the generator
	gross electric	VI.D.1.b and VI.B.2 (pp. 65-66, 102)	Measure electric power at the generator terminals
	net thermal (by simplified approach)	VI.D.2 (pp. 102-105)	Measure thermal energy sold and thermal energy going into a useful process
	gross thermal (by simplified approach)	VI.D.3 (pp. 105-109)	Measure thermal energy exiting the steam turbine
	net thermal (by boiler efficiency approach)	VI.D.4 (pp. 124-128)	Measure thermal energy sold and thermal energy going into a useful process, less any thermal energy returned to boiler in boiler feedwater, make up water, or steam return for reheating
	gross thermal (by boiler efficiency approach)	VI.D.5 (pp. 128-132)	Measure thermal energy exiting the steam turbine, less any thermal energy returned to boiler in boiler feedwater, make up water, or steam return for reheating
Combustion turbine cogenerator (Figure 5, pp. 94, 116)	net electric	VI.D.1.a and VI.B.1 (pp. 63-65, 102)	Measure electric power sold and power used in a useful process, less any incoming electricity provided to the plant during operation of the generator
	gross electric	VI.D.1.b and VI.B.2 (pp. 65-66, 102)	Measure electric power at the generator terminals
	net thermal (by simplified approach)	VI.D.2 (pp. 102-105)	Measure thermal energy sold and thermal energy going into a useful process
	gross thermal (by simplified approach)	VI.D.3 (pp. 105-109)	Measure thermal energy leaving the heat recovery steam generator (HRSG)
	net thermal (by boiler efficiency approach)	VI.D.4 (pp. 124-128)	Measure thermal energy sold and thermal energy going into a useful process, less any thermal energy returned to HRSG in boiler feedwater, make up water, or steam return for reheating
	gross thermal (by boiler efficiency approach)	VI.D.5 (pp. 128-132)	Measure thermal energy leaving the boiler, less any thermal energy returned to HRSG in boiler feedwater, make up water, or steam return for reheating

If you look at this facility type	and you require this type of output to be used for allocations	there are more details here	and this is the most common approach to monitoring output
Combined cycle cogenerator with process use of steam downstream of the steam turbine (Figure 6, pp. 95, 117)	net electric	VI.D.1.a and VI.B.1 (pp. 63-65, 102)	Measure electric power sold and power used in a useful process, less any incoming electricity provided to the plant during operation of the generator
	gross electric	VI.D.1.b and VI.B.2 (pp. 65-66, 102)	Measure electric power at the generator terminals
	net thermal (by simplified approach)	VI.D.2 (pp. 102-105)	Measure thermal energy sold and thermal energy going into a useful process
	gross thermal (by simplified approach)	VI.D.3 (pp. 105-109)	Measure thermal energy exiting the steam turbine
	net thermal (by boiler efficiency approach)	VI.D.4 (pp. 124-128)	Measure thermal energy sold and thermal energy going into a useful process, less any thermal energy returned to HRSG in boiler feedwater, make up water, or steam return for reheating
	gross thermal (by boiler efficiency approach)	VI.D.5 (pp. 128-132)	Measure thermal energy exiting the steam turbine, less any thermal energy returned to HRSG in boiler feedwater, make up water, or steam return for reheating
Steam cogenerator or combined cycle cogenerator with process use of superheated steam upstream of the steam turbine	net electric	VI.D.1.a and VI.B.1 (pp. 63-65, 102)	Measure electric power sold and power used in a useful process, less any incoming electricity provided to the plant during operation of the generator
	gross electric	VI.D.1.b and VI.B.2 (pp. 65-66, 102)	Measure electric power at the generator terminals
	net thermal (by simplified approach)	VI.D.2 (pp. 102-105)	Measure thermal energy sold and thermal energy going into a useful process
	gross thermal (by simplified approach)	VI.D.3 (pp. 105-109)	Measure thermal energy leaving the boiler or HRSG, less any thermal energy entering the steam turbine
	net thermal (by boiler efficiency approach)	VI.D.4 (pp. 124-128)	Measure thermal energy sold and thermal energy going into a useful process, less any thermal energy returned to the boiler or HRSG in boiler feedwater, make up water, or steam return for reheating
	gross thermal (by boiler efficiency approach)	VI.D.5 (pp. 128-132)	Measure thermal energy leaving the boiler, less any thermal energy returned to HRSG in boiler feedwater, make up water, or steam return for reheating and less any thermal energy entering the steam turbine

B. How could sources monitor electric output only at a conventional electric power plant?

Your State rule will require that electric generating facilities monitor either gross electric output or net electric output. Monitoring net output is described in section 1, "*Net Electric Output*" (pp. 63-65) and monitoring gross output is described in section 2., "*Gross Electric Output*" (pp. 65-66). Conventional power plants (non-cogeneration) will monitor only electric output. Table E-1 below (p. 62) describes locations for measuring electric output from a conventional power plant that receives allocations based upon electric output only. Figure 1 below (p. 61) is a simplified diagram picturing the measurement points described below at a conventional power plant. Cogeneration units which generate both electric output and thermal output are discussed below in Section VI.D., "How could sources monitor electric and thermal output at a cogeneration facility?" (pp. 92-137). In all cases below except those that specifically state otherwise, we assume that the measured output is recorded in a datalogger or computer on an hourly basis.

FIGURE 1: Electric Generator

Figure 1
Electric Generator

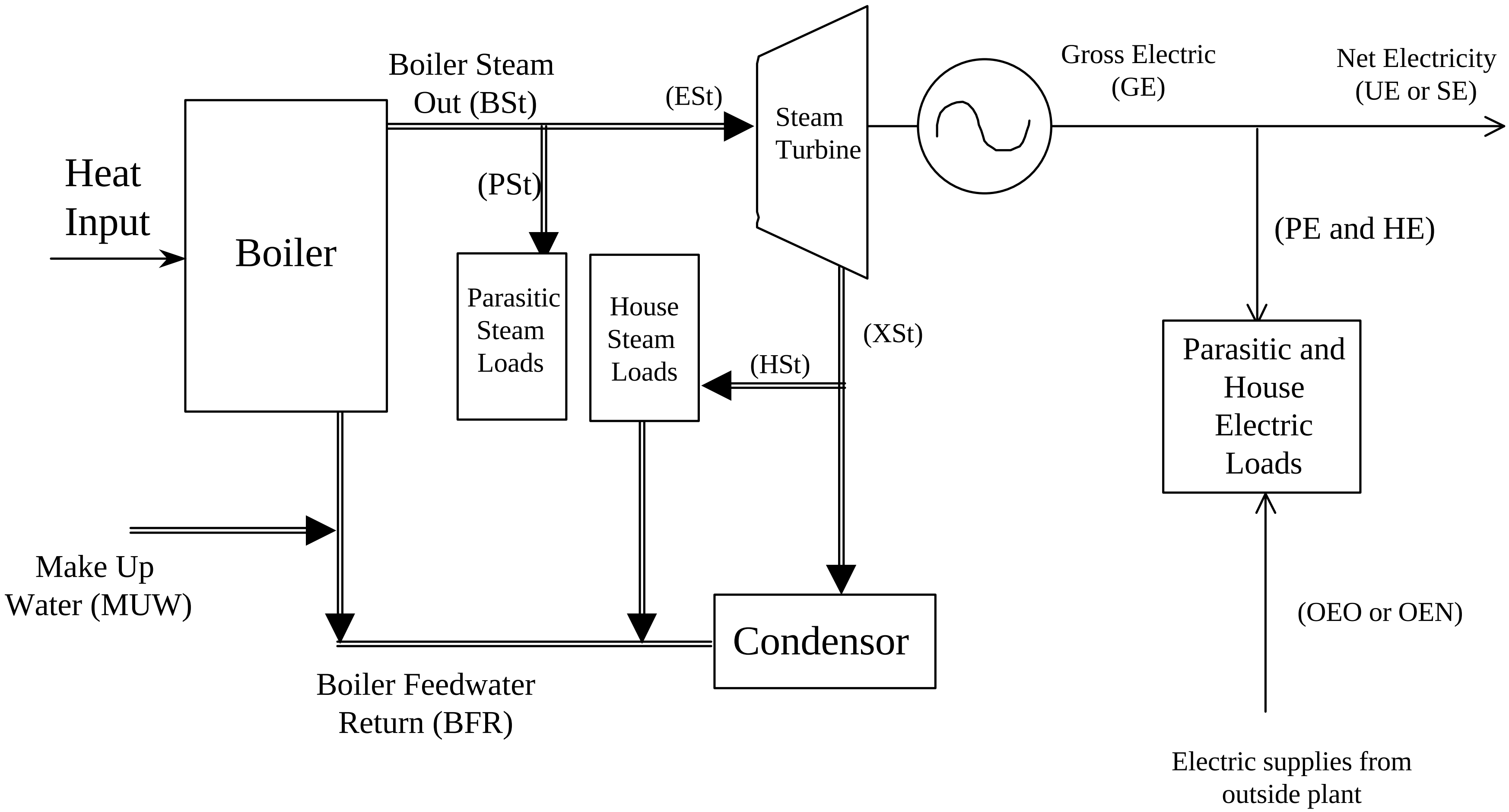

Table E-1, Monitoring Electric Output Only from an EGU						
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams.	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Net Electric Output		Gross Electric Output	
			Net measured directly (Primary)	Gross less parasitic and house loads	Gross measured directly (Primary)	Measure net plus parasitic and house loads
Column 1	2	3	4	5	6	7
Electric Generation	GE	Electric power measured at generator terminals	--	Measure(+)	Measure (+)	–
	SE	Electric power leaving plant to electric grid	Measure (+)	--	--	Measure (+)
	UE	Useful electric power (i.e., purposes other than sale, transmission to the grid, or generation of electricity)	Measure (+)			Measure (+)
Electricity Used on Site Not Generated by the Facility	OEO	Electric power for generation coming from grid or other power source to plant during operation	Measure (-)	Measure(-)	--	Measure (-)
	OEN	Electric power coming from grid or other source during non operation	--	--	--	--
Losses Associated with Electrical Generation	PE	Parasitic electric loads	--	Measure or use estimates which overstate loads (-)	--	Measure or estimate (+)
	HE	House electric loads	--	Measure or use estimates which overstate loads (-)	--	Measure or estimate (+)

1. *Net Electric Output.*

Monitoring equipment locations are described in Table E-1, columns 4 and 5 for EGUs monitoring only net electric output (p. 62).

Primary approach a. Measuring net electric output directly. For a source required to monitor net electric output only, the output monitoring system would monitor the amount of electricity sold, transmitted from the plant to the grid, or used for a purpose other than sale, transmission to the grid, or generating electricity at that plant[14], and any incoming electricity provided to the plant from another source (See Table E-1, column 4). Plants which sell electricity may use the billing meters for measuring electric sales and should not be required to install additional output monitoring equipment for record keeping purposes (i.e., datalogger or computer).

$$E_{net} = \sum_{\text{Electricity sold or used}} E_{elect} - \sum_{\substack{\text{Incoming electricity during} \\ \text{generator operation}}} E_{elect}$$

Where:

E_{net} is the net electricity generated by the plant

E_{elect} is the electricity measured at each point

"Electricity sold or used" is the number of places where electricity is sold or is transmitted from the plant (Location SE in Figure 1) or is used in a process other than generating electricity (UE in Table E-1)[15]

"Incoming electricity during generator operation" is the number of places where the plant

[14] It is possible that a source would use electricity within the plant in a useful process, such as operating industrial equipment to manufacture a product. This also should be measured as net electric output. (Location UE in Figures 4, 5, and 6) As a guideline, if some electricity used in the plant is used in the process of generating electricity, and if that electricity would not be used if the generator were removed from the facility, then that electricity should not be considered net electric output. For example, power used within a power plant to pulverize coal so that electricity can be generated would not be net electric output.

[15] Same as footnote 14.

receives electricity from another source during operation of the generator (Location OEO in Figure 1)

Alternative b. Determining net electric output using gross output measurements. For a source required to monitor net electric output which has gross output monitoring equipment installed on the generator terminals but does not have net output monitoring equipment installed, you may allow this source to determine net output as the gross output less all parasitic and house loads and less any electricity provided to the plant from another source while the generator produces electricity (See Table E-1, column 5). (It should not be necessary to measure electricity provided from another source while the generator is not operating, when there is no gross generation.)

$$E_{net} = \sum_{\text{Gross generation}} E_{elect} - \sum_{\text{Parasitic and house loads}} E_{elect} - \sum_{\substack{\text{Incoming electricity during} \\ \text{generator operation}}} E_{elect}$$

E_{net} is the net electricity generated by the plant

E_{elect} is the electricity measured at each point

"Gross generation" is each location where the source measures gross electric directly. (Location GE in Figure 1)

"Parasitic and house loads" is each location where the source measures or determines losses of electricity from parasitic (auxiliary) or house loads. (Locations PE and HE in Figure 1)

"Incoming electricity during generator operation" is each location where the source receives power from outside the plant while the generator is operating. (Location OEO in Figure 1)

Special case c. Both affected and non-affected units sharing a generator. In some cases, steam to a generator is supplied by both affected and non-affected units, such as when fossil fuel-fired and non-fossil fuel fired boilers feed steam to the same generator. It is also possible to have both affected and non-affected units located at a plant, where the source measures net electric output for the entire facility. In the first case, the company must develop an apportionment methodology to determine the amount of net electric output that is attributable to any affected units. In the second case, the company could opt-in the non-affected boilers or could develop an apportionment methodology. Several apportionment options exist including:

i. Apportion the electric output by steam energy supplied to the generator from each unit, or supplied to all generators at the plant. This requires monitoring steam supplied to each generator from each unit.

ii. Use unit heat input measured, recorded and reported using Part 75 procedures, Appendix F (i.e., stack flow monitor and diluent monitor or fuel flowmeters for gas and oil fired units). Note that you will be able to use this option if you measure heat input for individual units, but you will not be able to use heat input measured at a common stack or a common pipe.

2. *Gross Electric Output*.

Monitoring equipment locations for EGUs monitoring only gross electric output are described in Table E-1, columns 6 and 7 (p. 62).

Primary approach a. Measuring gross electric output directly. In the simplest and most common case, a facility which is required to monitor only gross electric output would measure the output from the generator at the generator terminals (See Table E-1, column 6).

Alternative b. Determining gross electric output using net output measurements. In the case where a facility has an existing output monitoring system for net electric output but does not measure electric output at the generator terminals, the gross output for this source may be estimated as either:

i. The sales of electricity using existing equipment (same as net electric output and always less than gross electric output). Under this approach, there should be no additional requirement for data collections in a datalogger or data acquisition and handling system (DAHS), as the billing measurement serves as the official record of output; or

ii The sales of electricity using existing equipment plus any measured parasitic or house electric load (See Table E-1, column 7). Under this option, a source may need to install extra electrical measurement equipment.

Special case

c. Both affected and non-affected units sharing a generator. If steam to a generator is supplied by both affected and non-affected units, an apportionment methodology must be developed to determine the amount of gross electric output that is attributable to the affected unit. Several apportionment options exist including:

i. Apportion the electric output by steam energy supplied to the generator from each unit. This requires monitoring steam supplied to the generator from each unit.

ii. Use unit heat input measured, recorded and reported using Part 75 procedures, Appendix F (i.e., stack flow monitor and diluent monitor or fuel flowmeters for gas and oil fired units). Note that you will be able to use this option if you measure heat input for individual units, but you will not be able to use heat input measured at a common stack or a common pipe.

Monitoring example for a conventional electric generator (power plant) (See Figure1, p. 61).
This is an example of a conventional power plant that produces only electric output. This figure would be similar for a non-emitting generating system; in that case, the energy source would replace the location marked "heat input" in the diagram.

The company could measure or estimate electric output as follows:

- Primary approach for net electric output: Net electric output measured directly would be UE+SE-OEO (Table E-1, column 4).
- Net electric output measured as gross electric output less house and parasitic loads would be GE-HE-PE-OEO (Table E-1, column 5)
- Primary approach for gross electric output: Gross electric output would be measured at the generator terminals GE. (Table E-1, column 6)
- Gross electric output estimated as net electric output would be UE+SE-OEO (Table E-1, column 7)
- Gross electric output measured or estimated as net electric output plus house and parasitic loads would be UE+SE+HE+PE-OEO (Table E-1, column 7).

Note that when switching from measuring gross output to calculating net output, or vice versa, you also need to measure any electricity coming into the plant from an outside source during operation of the generator for use in generating power (point OEO).

C. How could sources monitor thermal output at a steam generator?

Your State rule will require that sources monitor either gross thermal output or net thermal output. Non-electric generating units that are not cogeneration facilities (steam generators) will monitor only thermal output.

The Simplified Approach and the Boiler Efficiency Approach to Monitoring Thermal Output

We recommend that you require sources to monitor thermal output using one of the two following approaches: the simplified approach or the boiler efficiency approach. The boiler efficiency approach utilizes the traditional engineering approach to measuring thermal output where the thermal output is measured using an energy balance around the boiler or system to determine the energy transferred to the steam from combustion. The simplified approach measures thermal output in a single location, using a generic value for the energy returning to the boiler or system in boiler feedwater return or make up water as part of the allocation factor, rather than requiring measurement of the boiler feedwater return or make up water. Thus, if you compare Table BE-2 and Table SA-2 below, you will find that they are similar. However, four locations are not monitored under the simplified approach that might have to be monitored under the boiler efficiency approach: the boiler feedwater return, the make up water to the boiler, steam or hot water exiting a process, and return condensate or steam from a buyer.

Why do we provide you with two approaches? Both are valid approaches to monitoring output. However, there are issues you need to consider when deciding whether to require sources to measure thermal energy in the boiler feedwater return (condensate return) to a boiler. You might want to use the boiler efficiency approach, measuring the thermal energy in the boiler feedwater return for these reasons:

- Measuring the thermal energy going into and leaving the boiler reduces the possibility of “gaming” measurements of thermal output. Sources may perceive this approach as being more fair.
- The boiler efficiency approach is consistent with the approach that EIA takes when it receives thermal output data.
- Measuring the thermal energy going into and leaving the boiler is consistent with engineering practice for determining boiler efficiency, a familiar concept for boiler owners.

However, there are good reasons for preferring to use the simplified approach:

- The simplified approach encourages sources to take measures that improve the overall efficiency of making the plant's end product for sale, including returning condensate to the boiler instead of heating new, cold water.
- The simplified approach is simpler and will not require monitoring thermal energy on the boiler feedwater return line. This may reduce the overall monitoring burden for companies compared to the boiler efficiency approach.
- Our preliminary look at the possibility of gaming indicates that it may not be a major problem.

In deciding which approach to use for your State rule, you might take comment on issues such as:

- How many sources would need to install new monitoring equipment on the boiler feedwater return (condensate return) line if they monitor using the boiler efficiency approach?
- How much likelihood is there of gaming?
- How would companies prefer their competitors to measure their output?

Monitoring net thermal output under the simplified approach is described in section 1, "*Net Thermal Output under the Simplified Approach*,"(pp.74-76) and monitoring gross thermal output under the simplified approach is described in section 2, *"Gross Thermal Output under the Simplified Approach"* (pp. 76-78). Monitoring net thermal output under the boiler efficiency approach is described in section 3, "*Net Thermal Output under the Boiler Efficiency Approach*" (pp. 84-86), and monitoring gross thermal output under the boiler efficiency approach is described in section 4, *"Gross Thermal Output under the Boiler Efficiency Approach"* (pp. 87-89). Tables SA-2 and BE-2 below describes locations for measuring electric output from a steam generator that receives allocations based upon thermal output only (pp. 73, 83). Figure 2 below (pp. 71, 81) is a simplified diagram picturing the measurement points described below at a typical steam generator boiler; Figure 3 is similar, but shows a steam generator with a line returning steam to the boiler to be reheated (pp. 72,82). Figure 3 represents an unusual situation for an industrial boiler. Steam reheat is more common at EGUs. However, we include this example here to be comprehensive and to provide a simplified discussion of steam reheat, rather than a more complex, cogeneration situation with steam reheat. Cogeneration units which generate both electric output and thermal output are discussed below in section VI.D., "How could sources monitor electric and thermal output at a cogeneration facility?" (pp. 92-137). In all cases below except those that specifically state otherwise, we assume that the measured output is recorded in a datalogger or computer on an hourly basis.

Figure 2
Steam Generator

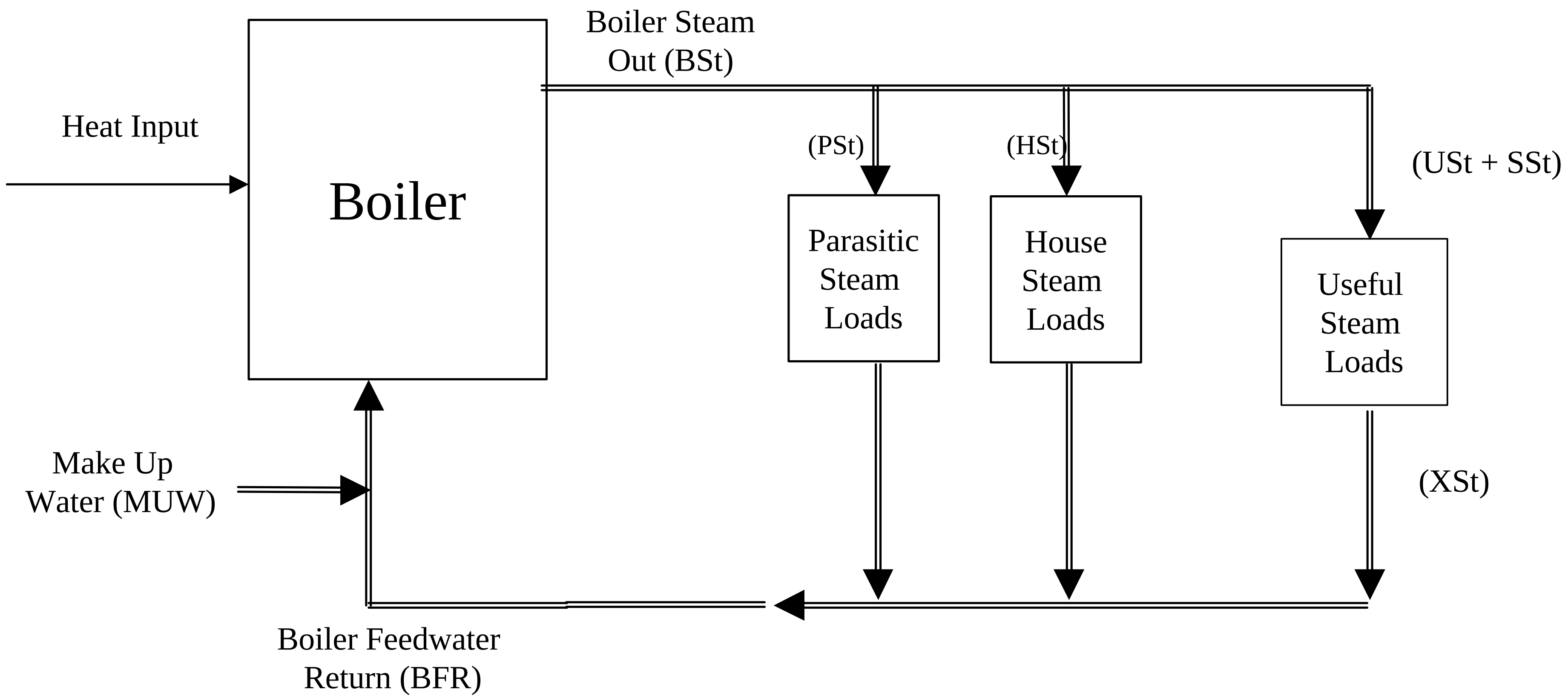

Figure 3
Steam Generator
(Industrial Boiler with Steam Reheat)

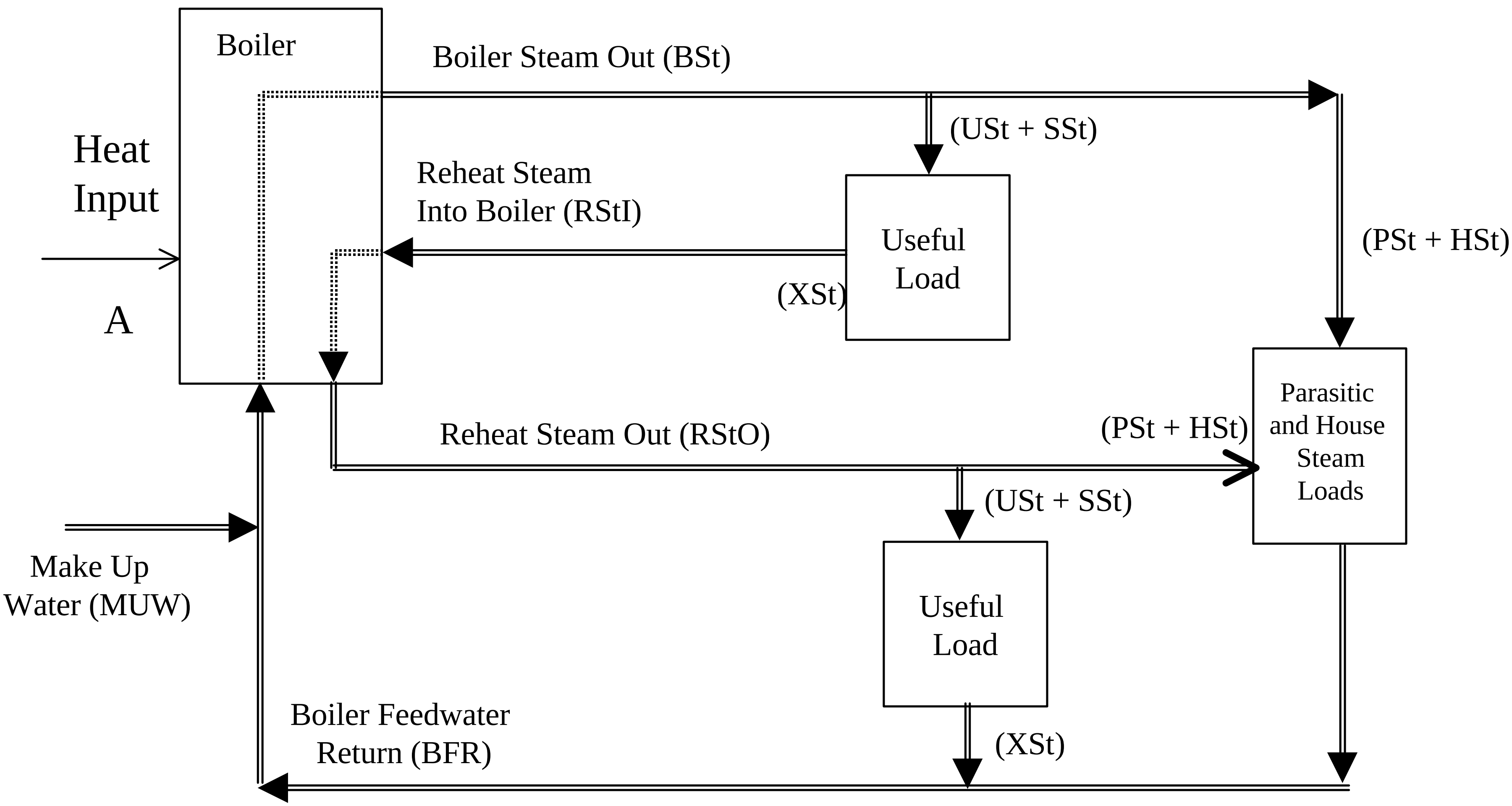

Table SA-2 Monitoring Thermal Output Only from a Steam Generator under the Simplified Approach						
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams.	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Gross Thermal Output Using the Simplified Approach		Net Thermal Output Using the Simplified Approach	
			Gross measured directly (Primary)	Net plus parasitic and house loads	Net measured directly (Primary)	Gross less parasitic and house loads
Column 1	2	3	4	5	6	7
Primary Steam System Note: flow in feedwater return and make up water must equal steam out flow	BSt	Main boiler steam out	Measure (+)	--		Measure (+)
	BFR	Boiler feedwater return	Not monitored under simplified approach			
	MUW	Make up water	Not monitored under simplified approach			
Steam Return and Reheat System Note: flow in reheat steam out must equal flow in reheat steam entering boiler	RStO	Reheat steam out	Measure (+)	--	--	Measure (+)
	RStI	Reheat steam returning to boiler	Measure (-)	--	--	Measure (-)
Useful Thermal Loads	USt	Useful steam or hot water entering a process	--	Measure (+)	Measure(+)	--
	XSt	Steam or hot water exiting a process	Not monitored under simplified approach			
	SSt	Steam sold at point of sale	--	Measure(+)	Measure(+)	--
	XSt	Return condensate or steam from buyer	Not monitored under simplified approach			
Losses Associated with Generation of Thermal Output	PSt	Parasitic steam loads	--	Measure (+)	--	Measure (-)
	HSt	House steam loads	--	Measure(+)	--	Measure (-)

1. *Net Thermal Output under the Simplified Approach.*

Net thermal output monitoring equipment locations are described in Table SA-2, columns 6 and 7 for industrial or institutional sources monitoring only net thermal output (p. 73). The basic approach is similar to that used for gross thermal output from a boiler, except that useful steam is measured, not gross steam from the boiler. "Useful steam" is steam (or hot water) used in a process that makes the product which is the purpose of the plant or steam that the plant sells. In contrast, steam used to heat the steam plant is a house load and is not considered "useful" because the source presumably would use that energy anyway, even if it were not making its final product at that time. Also, any thermal energy used in the process of generating the steam should not be considered net thermal output. In order to determine the energy in useful steam, a source would follow these steps:

Step 1: For saturated steam, measure or estimate the pressure of each stream of steam entering the useful process; temperature of saturated steam is determined by pressure. For superheated steam, measure or estimate the pressure and temperature of each stream of steam entering the useful process.

Step 2: Determine average hourly enthalpy (Btu/lb) from standard thermodynamic steam tables[16] for each stream of steam or hot water. (See section VI.E., "How do I calculate output data from supporting data?", pp. 138-141, for examples of how to do this.)

Step 3: Measure or estimate each total hourly flow of steam or hot water (lb).

Step 4: Use flow and enthalpy to determine the energy in the steam or hot water in mmBtu.

$$E_{stm}(mmBtu) = H\left(\frac{mmBtu}{lb}\right) \times Q(lb)$$

Where:

E_{stm} = total energy in steam or water for an hour

H = enthalpy from standard thermodynamic steam table

Q = total mass flow of steam or water for an hour

Step 5: Determine the net thermal output energy (mmBtu) as the total energy into any useful

[16] We recommend using "ASME Steam Tables: Thermodynamic and Tranposrt Properties of Steam" by the American Society of Mechanical Engineers, or tables from some other respected source or standard-setting organization.

process.

Approaches for determining net thermal output:

Primary approach: a. Measuring net thermal output directly. Determine the net thermal output energy (mmBtu) as the total energy into any useful process.

$$E_{net} = \sum_{\text{Themal energy in}} E_{stm}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Thermal energy in" is each location where thermal energy goes into a useful process. (Locations USt and SSt in Figures 2 and 3)

Alternative: b. Determining net thermal output measuring gross output. In the case where a facility measures the gross thermal output but does not measure the net thermal output directly, it is permissible to allow the source to determine net output as the gross thermal output less parasitic and house steam loads. In some cases it might be easier or more cost-effective to add monitors to measure or estimate the parasitic and house loads rather than installing a complete net output monitoring system to take account of thermal energy in such loads. (See Table SA-2, column 7)

$$E_{net} = \sum_{\text{Boiler thermal energy out}} E_{stm} - \sum_{\text{Parasitic and house thermal loads}} E_{stm}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Boiler thermal energy out" is each location where thermal energy leaves the boiler. (Locations BSt in Figures 2 and 3 and RStO in Figure 3)

"Parasitic and house thermal loads" is each location where the source measures or determines losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Locations PSt and HSt in Figures 2 and 3)

Under this approach, you should require monitoring of the flow and pressure, and temperature for superheated steam, for each of the major input and output streams. The energy of small streams or the effects of very minor losses such as small steam leaks may be estimated or ignored. A good starting point for determining what is a minor loss might be a value less than 1% of the total gross steam output. The steam temperature, pressure, and flow rate values should, at a minimum, be recorded as hourly averages in a datalogger.

2. *Gross Thermal Output under the Simplified Approach*.

Monitoring locations are described in Table SA-2, columns 4 and 5 for a source monitoring only gross thermal output (p. 73). Under this approach, companies would measure the energy in steam leaving the boiler only to determine gross thermal output, in $mmBtu_{out}$. Companies would not need to measure the energy in hot water reentering the boiler in the boiler feedwater return. This approach requires a source to determine the energy in the steam using the procedure below:

Step 1: For saturated steam, measure or estimate the pressure of each stream of steam leaving the boiler; temperature of saturated steam is determined by pressure. For superheated steam, measure or estimate the pressure and temperature of each stream of steam leaving the boiler.

Step 2: Determine average hourly enthalpy (Btu/lb) from standard thermodynamic steam tables[17] for each stream of steam. (See section VI.E., "How do I calculate output data from supporting data?", pp. 138-141, for examples of how to do this.)

Step 3: Measure or estimate each total hourly flow of steam or hot water (lb).

Step 4: Use flow and enthalpy to determine the energy in the steam or hot water in mmBtu.

[17] Same as footnote 16.

$$E_{stm}(mmBtu) = H\left(\frac{mmBtu}{lb}\right) \times Q(lb)$$

Where:

E_{stm} = total thermal energy in steam or water for an hour

H = enthalpy from standard thermodynamic steam table

Q = total mass flow of steam or water for an hour

Step 5: Determine the gross thermal output energy ($mmBtu_{out}$) as the total energy out of the boiler.

Note that steps 2 through 5 are the same as steps 2 through 5 for determining net thermal output in section VI.C.1., "Net Thermal Output under the Simplified Approach" (p. 74-76)

Approaches for determining gross thermal output:

Primary approach: a. Measuring gross thermal output directly. In the most basic case, a company would measure the energy leaving a boiler. The company would measure the output thermal energy of each flow of steam or water out of the boiler (See Table SA-2, column 4)

$$E_{gross} = \sum_{\text{Boiler thermal energy out}} E_{stm}$$

Where:

E_{gross} is the gross thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Boiler thermal energy out" is each location where thermal energy leaves the boiler. (Locations BSt in Figures 2 and 3 and RStO in Figure 3)

Alternative: b. Determining gross thermal output by measuring net output. In the case where a facility sells steam to a non-affiliated source under contract and wishes to use the output monitoring system associated with these sales to estimate gross output, the gross thermal output may be estimated as either: (a) the sales of steam converted to mmBtu using flow and the steam tables, or (b) the sales of steam converted to mmBtu plus any other measured steam not sold (See Table SA-2, column 5). Note that in the case of steam sales if hourly data is recorded for billing purposes, this record should serve as the official record of output and additional data recording in a datalogger is not necessary.

$$E_{gross} = \sum_{\text{Thermal energy sold}} E_{stm}$$

or

$$E_{gross} = \sum_{\text{Thermal energy sold}} E_{stm} + \sum_{\text{Parasitic or house thermal loads}} E_{stm}$$

Where:

E_{gross} is the gross thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Thermal energy sold" is the number of places where steam or thermal energy is sold by the plant (Location SSt in Figures 2 and 3)

"Parasitic or house thermal loads" is each location where the source measures or determines losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Locations HSt and PSt in Figures 2 and 3)

Under this approach, you should require monitoring of the flow and pressure, and temperature for superheated steam, for each of the major streams leaving the boiler. The energy of small streams or the effects of very minor losses such as small steam leaks may be estimated or ignored. A good starting point for determining what is a minor loss might be a value less than 1% of the total gross steam output. The steam temperature, pressure, and flow rate values should, at a minimum, be recorded as hourly averages in a datalogger.

Monitoring example for a steam generator under the simplified approach (see Figure 2, p. 71)

This is an example of a very simple steam boiler with the ability to measure the gross steam out at a single location (presumably at the boiler outlet). See Table SA-2, p. 73.

The company could measure or estimate thermal output as follows:

- Primary approach for net thermal output: Net thermal output measured directly would be (USt+SSt) (Table SA-2, column 6).
- Net thermal output determined as gross thermal output less parasitic and house steam loads would be (BSt-PSt-HSt) (Table SA-2, column 7).
- Primary approach for gross thermal output: Gross thermal output measured directly (Table SA-2, column 4) would be BSt (Table SA-2, column 4).
- Gross thermal output estimated as net output would be USt+SSt (Table SA-2, column 6).
- Gross thermal output measured as net thermal output plus parasitic and house loads would be (USt+SSt+PSt+HSt) (Table SA-2, column 5).

Monitoring example for a steam generator with steam reheat under the simplified approach. (see Figure 3, p. 72)

This is an example of a more sophisticated steam boiler where the boiler has a steam reheat cycle. In this case, the boiler has two steam headers from which thermal output must be measured. The monitoring is similar to that in Figure 2 with additional monitoring required at the inlet and outlet of the steam reheat cycle. See Table SA-2, p. 73.

The company could measure or estimate thermal output as follows:

- Primary approach for net thermal output: Net thermal output measured directly would be (USt+SSt-RStI) (Table SA-2, column 6).
- Net thermal output determined as gross thermal output less losses would be (BSt+RStO-RStI-PSt-HSt) (Table SA-2, column 7).
- Primary approach for gross thermal output: Gross thermal output measured directly would be BSt+RStO-RStI (Table SA-2, column 4).
- Gross thermal output measured as net thermal output would be USt+SSt-RStI (Table SA-2, column 5).
- Gross thermal output measured as net thermal output plus parasitic and house loads would be USt+SSt+PSt+HSt-RStI (Table SA-2, column 5).

Figure 2
Steam Generator

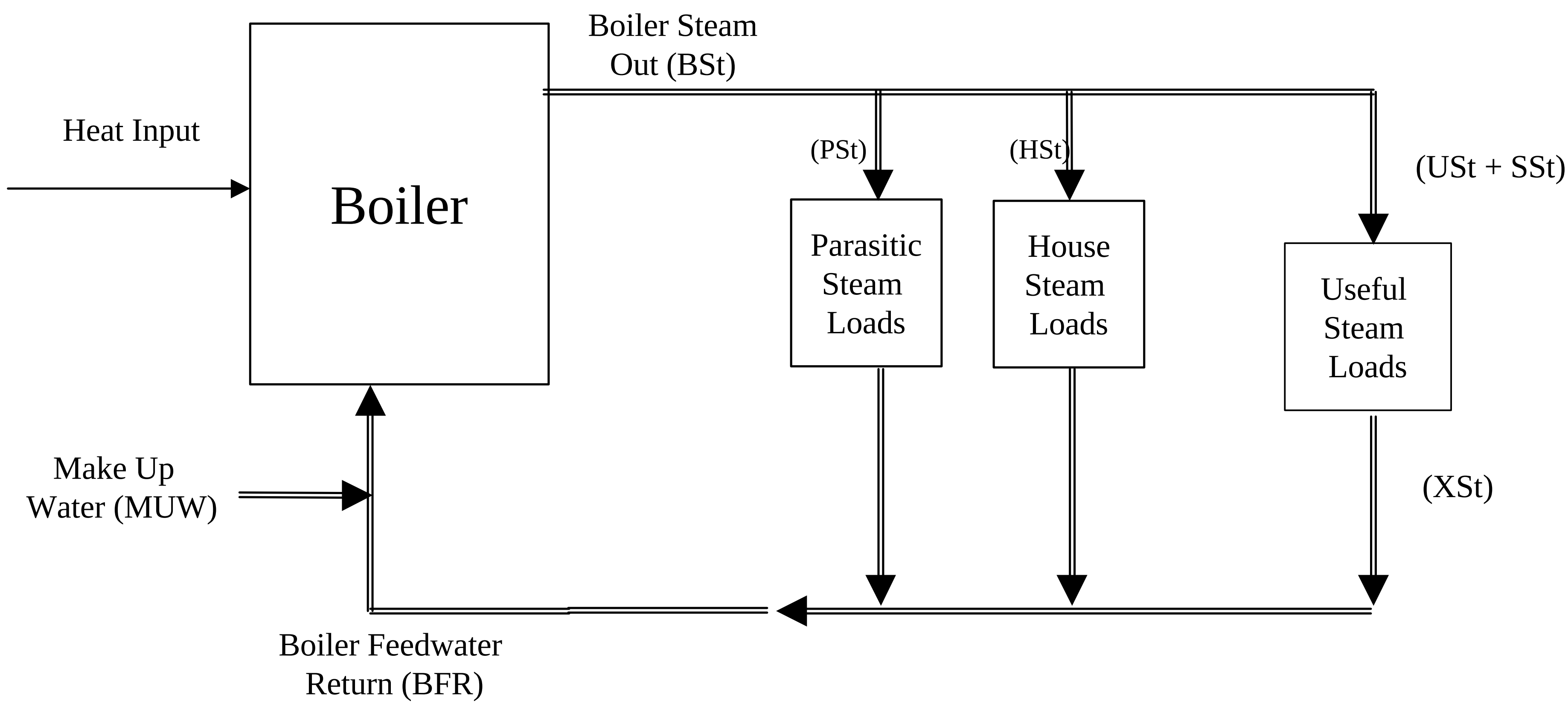

FIGURE 2 (repeated)

F I GU RE 3 (re pea ted)

Figure 3
Steam Generator
(Industrial Boiler with Steam Reheat)

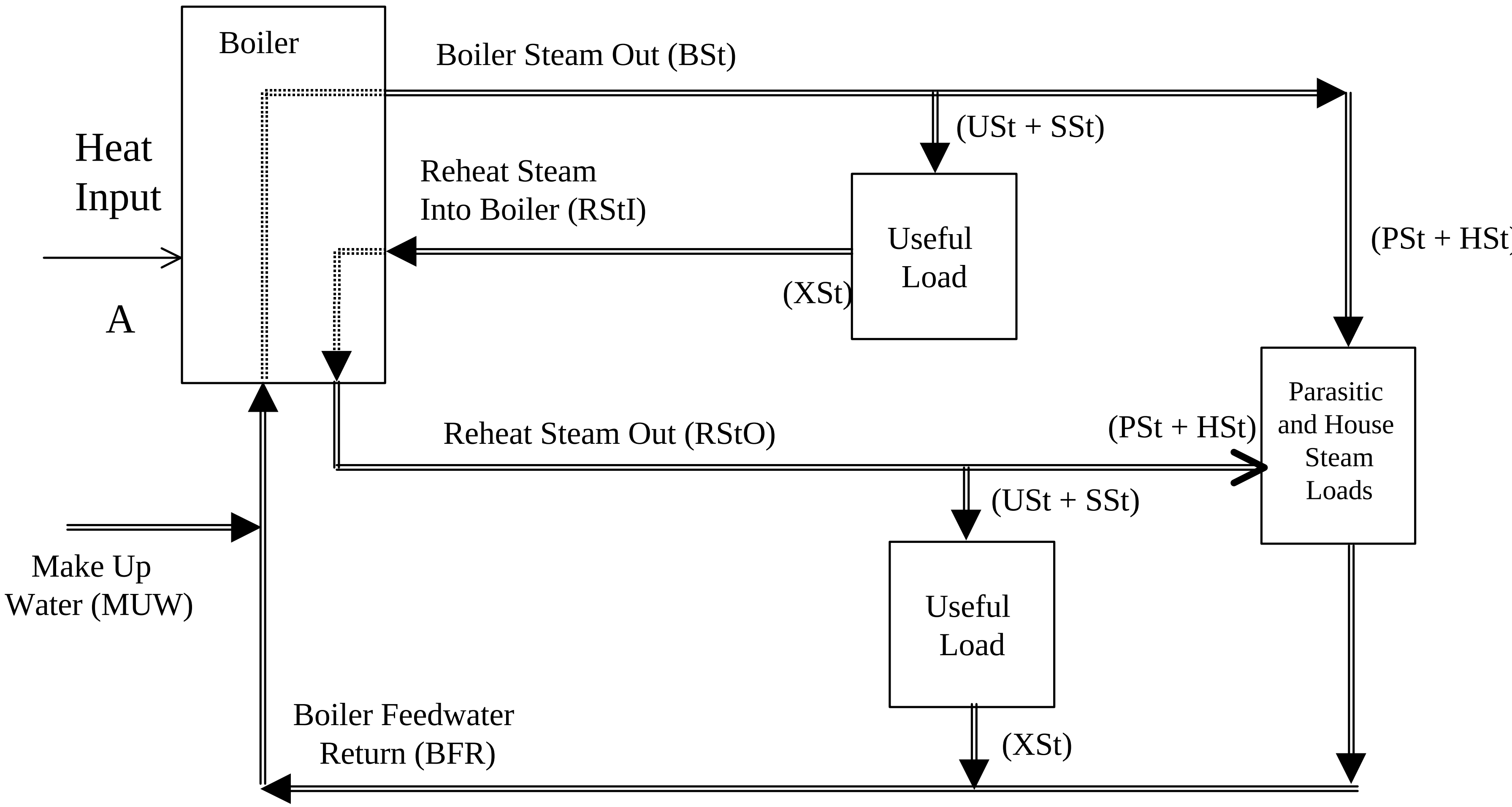

Table BE-2 Monitoring Thermal Output Only from a Steam Generator under the Boiler Efficiency Approach						
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams.	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Gross Thermal Output Using the Boiler Efficiency Approach		Net Thermal Output Using the Boiler Efficiency Approach	
			Gross measured directly (Primary)	Net plus parasitic and house loads	Net measured directly (Primary)	Gross less parasitic and house loads
Column 1	2	3	4	5	6	7
Primary Steam System Note: flow in feedwater return and make up water must equal steam out flow	BSt	Main boiler steam out	Measure (+)	--		Measure (+)
	BFR	Boiler feedwater return	Measure or estimate(-)	Measure or estimate (-)	Measure (-)	Measure (-)
	MUW	Make up water	Measure or estimate(-)	Measure or estimate (-)	Measure (-)	Measure (-)
Steam Return and Reheat System Note: flow in reheat steam out must equal flow in reheat steam entering boiler	RStO	Reheat steam out	Measure (+)	--	--	Measure (+)
	RStI	Steam returning to boiler for reheating	Measure (-)	--	--	Measure (-)
Useful Thermal Loads	USt	Useful steam or hot water entering a process	--	Measure (+)	Measure(+)	--
	XSt	Steam or hot water exiting a process	--	--	--	--
	SSt	Steam sold at point of sale	--	Measure(+)	Measure(+)	--
	XSt	Return condensate or steam from buyer	--	--	--	--
Losses Associated with Generation of Thermal Output	PSt	Parasitic Steam Loads	--	Measure (+)	--	Measure (-)
	HSt	House Steam Loads	--	Measure(+)	--	Measure (-)

3. *Net Thermal Output under the Boiler Efficiency Approach.*

Net thermal output monitoring equipment locations are described in Table BE-2, columns 6 and 7 (p. 83) for industrial or institutional sources monitoring only net thermal output (non-cogeneration). The basic approach is similar to that used for gross thermal output from a boiler, except that the energy balance developed is around the useful steam, not the boiler. "Useful steam" is steam (or hot water) used in a process that makes the product which is the purpose of the plant or steam that the plant sells. In contrast, steam used to heat the steam plant is a house load and is not considered "useful" because the source presumably would use that energy anyway, even if it were not making its final product at that time. Also, any thermal energy used in the process of generating the steam should not be considered net thermal output. In order to determine the energy in useful steam, a source would follow these steps:

Step 1: Perform a mass balance on water and steam into each useful process (that is, each process that makes the plant's product) and water and steam out of each useful process. One would treat all steam sold as entering a useful process.

Step 2: For saturated steam, measure or estimate the pressure of each stream of steam or hot water entering or leaving the useful process; temperature of saturated steam is determined by pressure. For superheated steam, measure or estimate the pressure and temperature of each stream of steam or hot water entering or leaving the useful process.

Step 3: Determine average hourly enthalpy (Btu/lb) from standard thermodynamic steam tables[18] for each stream of steam or hot water. (See section VI.E., "How do I calculate output data from supporting data?", pp. 138-141, for examples of how to do this.)

Step 4: Measure or estimate each total hourly flow of steam or hot water (lb).

Step 5: Use flow and enthalpy to determine the energy in the steam or hot water in mmBtu.

[18] Same as footnote 16.

$$E_{stm}(mmBtu) = H\left(\frac{mmBtu}{lb}\right) \times Q(lb)$$

Where:

E_{stm} = total energy in steam or water for an hour

H = enthalpy from standard thermodynamic steam table

Q = total mass flow of steam or water for an hour

Step 6: Determine the net thermal output energy (mmBtu) as the total energy into any useful process of the boiler less the energy out of the process.

Note that steps 3 through 6 are the same as steps 2 through 5 for determining net thermal output in section VI.C.1., "Net Thermal Output under the Simplified Approach" (p. 74-76).

Approaches for determining net thermal output:

Primary approach: a. Measuring net thermal output directly. In the case where a source uses steam internally or sells steam to an outside party, the energy balance is developed around all useful processes or sales. The company would measure the input and output thermal energy of each flow or steam or water into and out of the useful process (See Table BE-2, column 6)

$$E_{net} = \sum_{\text{Themal energy in}} E_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Thermal energy in" is each location where thermal energy goes into a useful process. (Locations USt and SSt in Figures 2 and 3)

"Thermal energy returning to boiler" is each location where thermal energy enters the boiler in a return line. (Locations BFR in Figures 2 and 3 and RStI in Figure 3)

Note that this is a slightly different estimate of net thermal output than measuring the steam or water exiting a process or returning from a sales agreement as described in

Step 6 above. In Step 6, there could be additional energy added to the condensate from the house and parasitic loads that are not measured.

Alternative

b. Determining net thermal output measuring gross output. In the case where a facility measures the gross thermal output but does not measure the net steam directly, it is permissible to allow the source to determine net output as the gross steam less parasitic and house steam loads. In some cases it might be easier or more cost-effective to add monitors to measure or estimate the parasitic and house loads rather than installing a complete net output monitoring system to take account of thermal energy in and out of such loads. (See Table BE-2, column 7).

$$E_{net} = \sum_{\text{Boiler thermal energy out}} E_{stm} - \sum_{\text{Parasitic and house thermal loads}} E_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Boiler thermal energy out" is each location where thermal energy leaves the boiler. (Locations BSt in Figures 2 and 3 and RStO in Figure 3)

"Parasitic and house thermal loads" is each location where the source measures or determines losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Locations PSt and HSt in Figures 2 and 3)

"Thermal energy returning to boiler" is each location where thermal energy enters the boiler in a return line. (Locations BFR in Figures 2 and 3 and RStI in Figure 3)

Under this approach, you should require monitoring of the flow and pressure, and temperature for superheated steam for each of the major streams entering and leaving the boiler. The energy of small streams or the effects of very minor losses such as small steam leaks may be estimated or ignored. A good starting point for determining what is a minor loss might be a value less than 1% of the total gross steam output. The steam temperature, pressure, and flow rate values should, at a minimum, be recorded as hourly averages in a datalogger.

4. *Gross Thermal Output under the Boiler Efficiency Approach.*

Monitoring locations are described in Table BE-2, columns 4 and 5 for a source monitoring only gross thermal output (p. 83). Under this approach, boilers would measure the energy imparted to the steam from combustion to determine gross thermal output, in $mmBtu_{out}$. This approach requires a source to determine the energy imparted to the steam from combustion using the procedure below:

Step 1: Perform a mass balance on water and steam into the boiler and water and steam out of the boiler.

Step 2: For saturated steam, measure or estimate the pressure of each stream of steam or hot water entering or leaving the boiler; temperature of saturated steam is determined by pressure. For superheated steam, measure or estimate the pressure and temperature of each stream of steam or hot water entering or leaving the boiler.

Step 3: Determine average hourly enthalpy (Btu/lb) from standard thermodynamic steam tables[19] for each stream of steam or hot water. (See section VI.E., "How do I calculate output data from supporting data?", pp. 138-141, for examples of how to do this.)

Step 4: Measure or estimate each total hourly flow of steam or hot water (lb).

Step 5: Use flow and enthalpy to determine the energy in the steam or hot water in mmBtu.

$$E_{stm}(mmBtu) = H\left(\frac{mmBtu}{lb}\right) \times Q(lb)$$

Where:

E_{stm} = total thermal energy in steam or water for an hour

H = enthalpy from standard thermodynamic steam table

Q = total mass flow of steam or water for an hour

Step 6: Determine the gross thermal output energy ($mmBtu_{out}$) as the total energy out of the boiler less the energy into the boiler.

Note that steps 3 through 6 are the same as steps 3 through 6 for determining net

[19] Same as footnote 16.

thermal output in section VI.C.3., “Net Thermal Output under the Boiler Efficiency Approach” (p. 84-86) and steps 2 through 5 for determining gross thermal output in section VI.C.2., “Gross Thermal Output under the Simplified Approach” (p. 76-78).

Approaches for determining gross thermal output:

Primary approach: a. Measuring gross thermal output directly. In the most basic case, a company would develop an energy balance around a boiler. The company would measure the input and output thermal energy of each flow of steam or water into and out of the boiler (See Table BE-2, column 4)

$$E_{gross} = \sum_{\text{Boiler thermal energy out}} E_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm}$$

Where:

E_{gross} is the gross thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

“Boiler thermal energy out” is each location where thermal energy leaves the boiler. (Locations BSt in Figures 2 and 3 and RStO in Figure 3)

“Thermal energy returning to boiler” is each location where thermal energy enters the boiler in a return line. (Locations BFR in Figures 2 and 3 and RStI in Figure 3)

Alternative b. Determining gross thermal output by measuring net output. In the case where a facility sells steam to a non-affiliated source under contract and wishes to use the output monitoring system associated with these sales to estimate gross output, the gross thermal output may be estimated as either: (a) the sales of steam converted to mmBtu using flow and the steam tables minus the input energy to the boiler in the return condensate or make up water, or (b) the sales of steam converted to mmBtu plus any other measured steam not sold minus the input energy to the boiler in the return condensate and make-up water (See Table BE-2, column 5). Note that in the case of steam sales if hourly data is recorded for billing purposes, this record should serve as the official record of output; thus, additional data recording in a datalogger is not necessary.

$$E_{gross} = \sum_{\text{Thermal energy sold}} E_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm}$$

or

$$E_{gross} = \sum_{\text{Thermal energy sold}} E_{stm} + \sum_{\text{Parasitic or house thermal loads}} E_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm}$$

Where:

E_{gross} is the gross thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

“Thermal energy sold” is the number of places where steam or thermal energy is sold by the plant (Location SSt in Figures 2 and 3)

“Parasitic or house thermal loads” is each location where the source measures or determines losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Locations HSt and PSt in Figures 2 and 3)

“Thermal energy returning to boiler” is each location where thermal energy enters the boiler in a return line. (Locations BFR in Figures 2 and 3 and RStI in Figure 3)

Under this approach, you should require monitoring of the flow and pressure, and temperature for superheated steam for each of the major streams entering or leaving the boiler. The energy of small streams or the effects of very minor losses such as small steam leaks may be estimated or ignored. A good starting point for determining what is a minor loss might be a value less than 1% of the total gross steam output. Sources may also rely on the conservation of mass in monitoring flow. In practice, this is done by measuring the flow of water or steam into a boiler and assuming that the flow out is equal, as it must be under steady-state conditions. The steam temperature, pressure, and flow rate values should, at a minimum, be recorded as hourly averages in a datalogger.

Monitoring example for a steam generator under the boiler efficiency approach (see Figure 2, p. 81)

This is an example of a very simple steam boiler with the ability to measure the gross steam out at a single location (presumably at the boiler outlet). See Table BE-2, p. 83.

The company could measure or estimate thermal output as follows:

- Primary approach for net thermal output: Net thermal output measured directly would be (USt+SSt-BFR-MUW) (Table BE-2, column 6).
- Net thermal output determined as gross thermal output less parasitic and house steam loads would be (BSt-BFR-MUW-PSt-HSt) (Table BE-2, column 7).
- Primary approach for gross thermal output: Gross thermal output measured directly (Table BE-2, column 4) would be BSt-BFR-MUW (Table BE-2, column 4).
- Gross thermal output estimated as net output would be USt+SSt-BFR-MUW (Table BE-2, column 6).
- Gross thermal output measured as net thermal output plus parasitic and house loads would be (USt+SSt+PSt+HSt-BFR-MUW) (Table BE-2, column 5).

Monitoring example for a steam generator with steam reheat under the boiler efficiency approach. (see Figure 3, p. 82)

This is an example of a more sophisticated steam boiler where the boiler has a steam reheat cycle. In this case, the boiler has two steam headers from which thermal output must be measured. The monitoring is similar to that in Figure 2 with additional monitoring required at the inlet and outlet of the steam reheat cycle. See Table BE-2, p. 83.

The company could measure or estimate thermal output as follows:

- Primary approach for net thermal output: Net thermal output measured directly would be (USt+SSt-BFR-MUW-RStI) (Table BE-2, column 6).
- Net thermal output determined as gross thermal output less losses would be (BSt+RStO-BFR-MUW-RStI-PSt-HSt) (Table BE-2, column 7).
- Primary approach for gross thermal output: Gross thermal output measured directly would be BSt+RStO-BFR-MUW-RStI (Table BE-2, column 4).
- Gross thermal output measured as net thermal output would be USt+SSt-BFR-MUW-RStI (Table BE-2, column 5).
- Gross thermal output measured as net thermal output plus parasitic and house loads would be USt+SSt+PSt+HSt-BFR-MUW-RStI (Table BE-2, column 5).

D. How could sources monitor electric and thermal output at a cogeneration facility?

Your State rule should require that cogeneration or combined heat and power (CHP) sources monitor both electric output and thermal output when a facility produces electricity and steam. You must also decide whether net or gross output should be monitored. You could allow sources to monitor a combination of net and gross output. These combinations are described in tables in this section[20]: monitoring net electric and net thermal output (Tables SA-4 and BE-4, pp. 98-99, 120-121); monitoring gross thermal and gross electric output (Tables SA-3 and BE-3, pp. 96-97, 118-119); and monitoring net electric and gross thermal output (Tables SA-5 and BE-5, pp. 100-101, 122-123).

Note that throughout this section for cogeneration facilities, the major difference between the simplified approach and the boiler efficiency approach is that under the simplified approach, it is not necessary to measure the thermal energy in the boiler feedwater return, the make up water to the boiler, condensate returned by a buyer, or the steam exiting a useful process. We have simplified the diagrams and discussion for cogeneration facilities by not including extra steam return to a boiler for reheating. However, in a situation including steam reheating, the source would need to measure the return line and the reheated steam exiting the boiler when measuring gross thermal output. The source also would need to measure the return line entering the boiler when measuring net thermal output.

[20]We also considered the possibility of measuring net thermal output and gross electric output. However, we decided that this was not a likely combination. Since it appears to be possible for sources to determine net electric output in all cases, a State is likely choose to require sources to determine gross electric output for policy reasons, rather than for practical reasons, and to require gross thermal output for the same policy reasons.

Figure 4
Steam Cogenerator

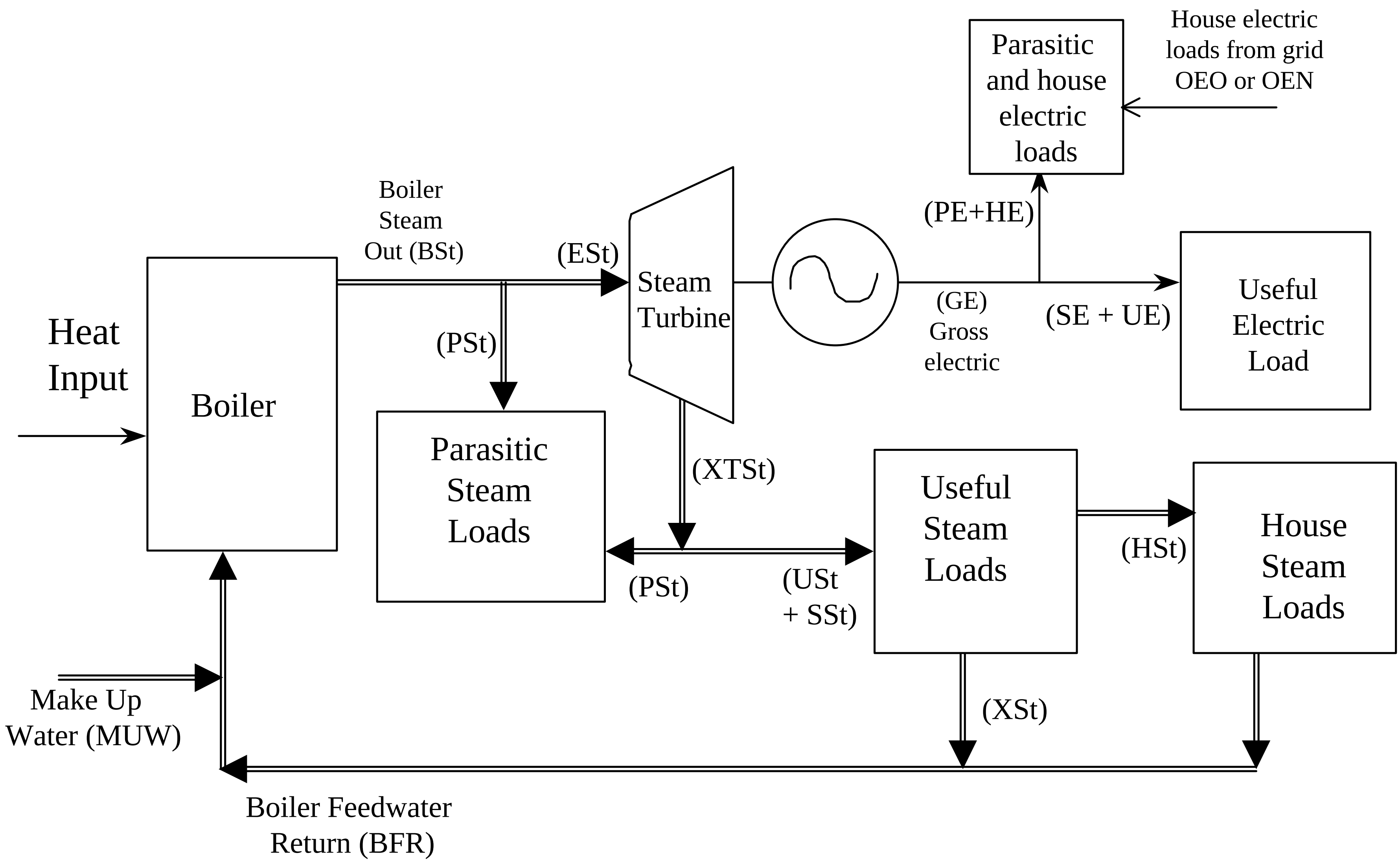

Figure 5
Combustion Turbine Cogenerator

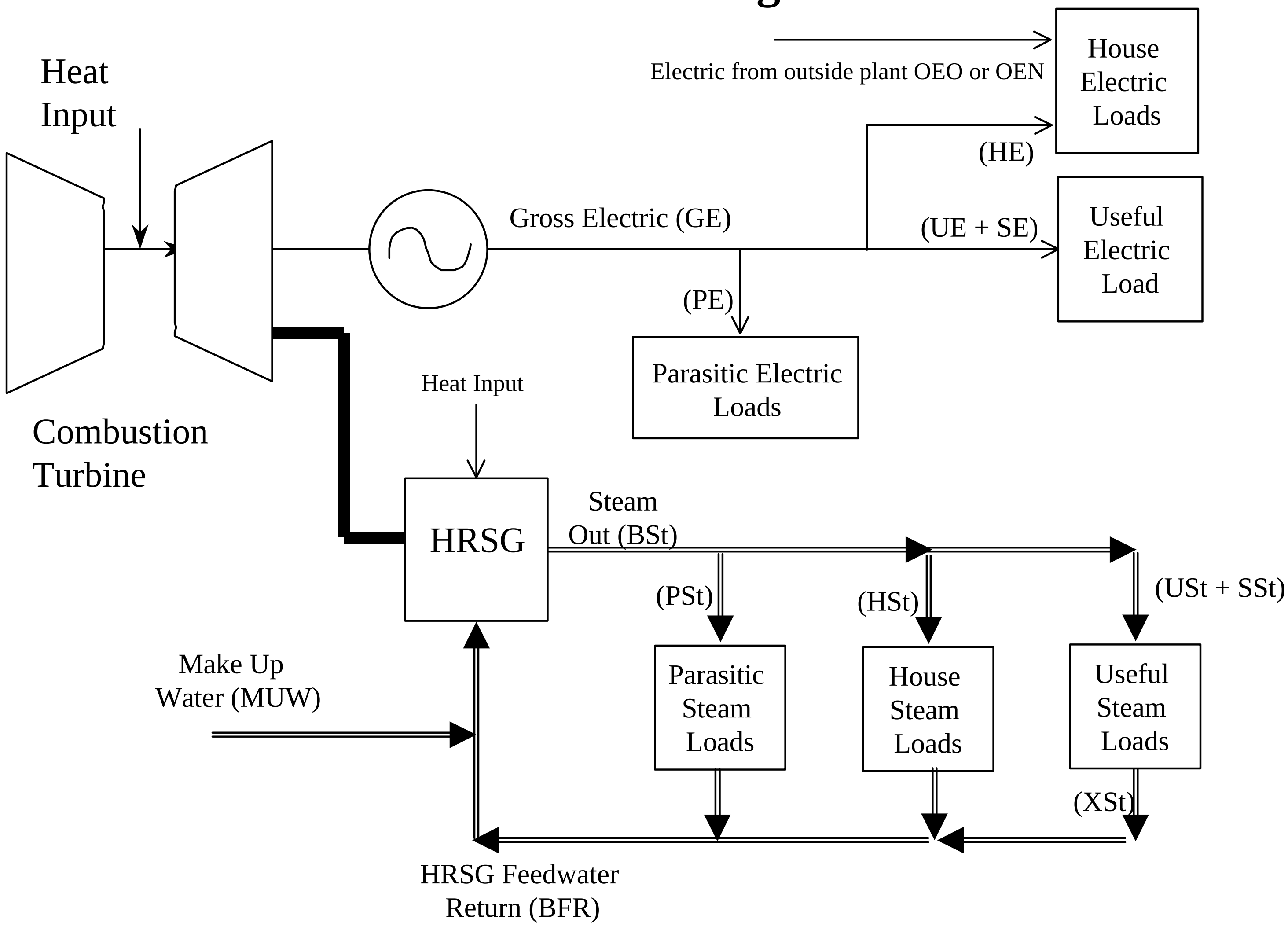

Figure 6
Combined Cycle Cogenerator

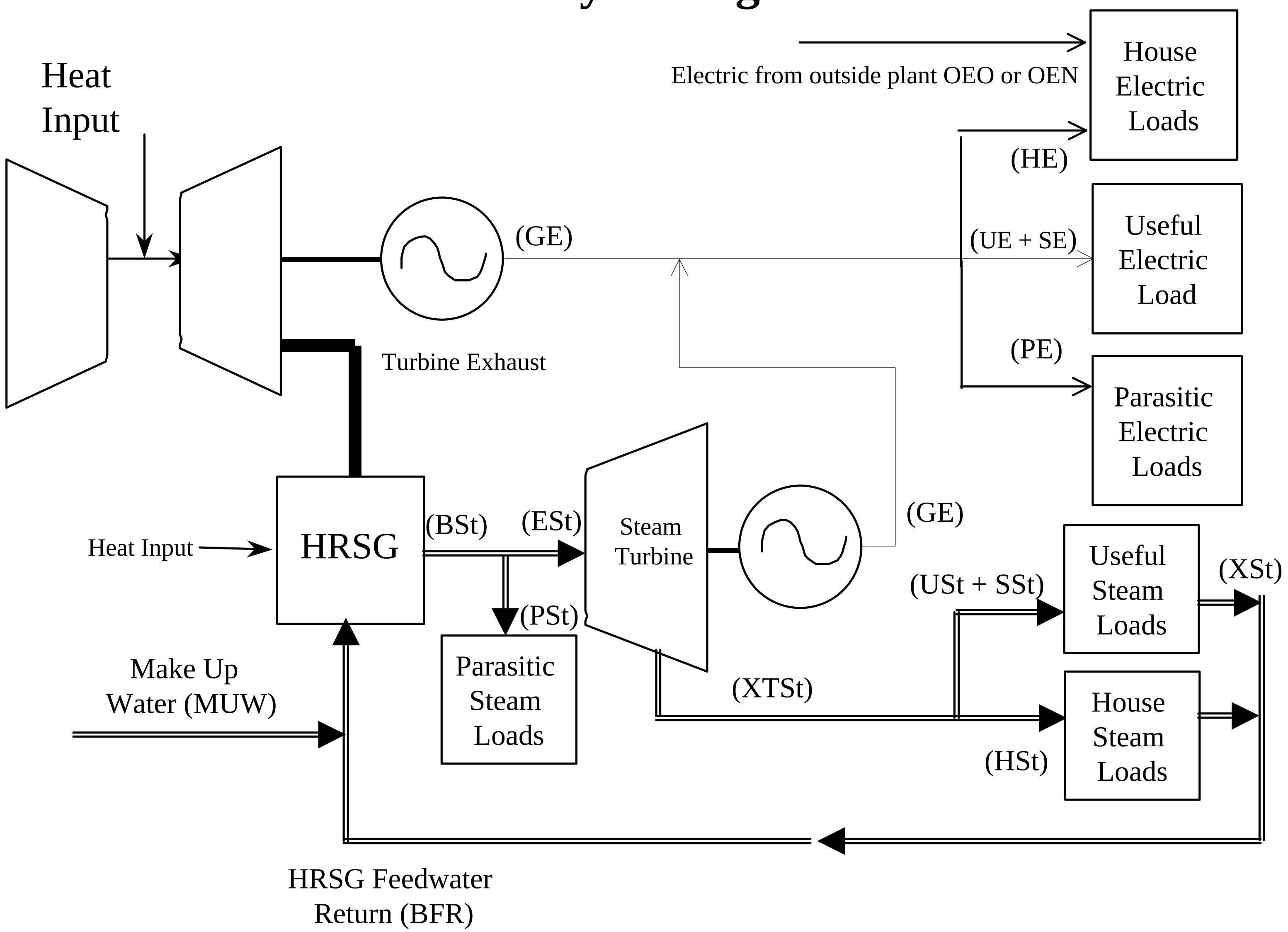

Table SA-3, Monitoring Cogenerator for Gross Electric Output and Gross Thermal Output under the Simplified Approach								
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Gross Thermal Output for Allocation				Gross Electric Output	
			Gross thermal output measured directly at exit from steam turbine (Primary)	Gross thermal output measured directly at HRSG/boiler less steam used for electric generation	Net thermal output plus parasitic and house loads less steam used for electric generation	Gross thermal output measured directly at HRSG/boiler less equivalent electric output in mmBtu.	Gross electric output measured directly (Primary)	Net electric output plus parasitic and hours loads
Column 1	2	3	4	5	6	7	8	9
Primary Steam System	BSt	Main boiler steam out	--	Measure(+)	--	Measure(+)	--	--
Note: flow in feedwater return and make up water must equal steam out flow	BFR	Boiler feedwater return	Not monitored under simplified approach					
	MUW	Make up water	Not monitored under simplified approach					
Steam Return and Reheat System	RStO	Reheat steam out	Measure(+)	Measure(+)	--	Measure(+)	--	--
Note: flow in reheat steam out must equal flow in reheat steam entering boiler	RStI	Steam returning to boiler for reheating	Measure(-)	Measure(-)	--	Measure(-)	--	--
Steam Used to Generate Electric Power in a Steam Turbine	ESt	Steam entering a turbine	--	Measure(-)	--	--	--	--
	XTSt	Steam exhaust from a turbine	Measure (+)	Measure (+)	--	--	--	--
Useful Thermal Loads	USt	Useful steam or hot water entering a process	--	--	Measure (+)	--	--	--
	XSt	Steam or hot water exiting a process	Not monitored under simplified approach					
	SSt	Steam sold at point of sale	--	--	Measure (+)	--	--	--
	XSt	Return condensate or steam from buyer	Not monitored under simplified approach					
Losses Associated with Generation of Thermal Output	PSt	Parasitic steam loads	--	--	Measure (+)	--	--	--
	HSt	House steam loads	--	--	Measure (+)	--	--	--

Table SA-3, Monitoring Cogenerator for Gross Electric Output and Gross Thermal Output under the Simplified Approach

Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Gross Thermal Output for Allocation				Gross Electric Output	
			Gross thermal output measured directly at exit from steam turbine (Primary)	Gross thermal output measured directly at HRSG/boiler less steam used for electric generation	Net thermal output plus parasitic and house loads less steam used for electric generation	Gross thermal output measured directly at HRSG/boiler less equivalent electric output in mmBtu.	Gross electric output measured directly (Primary)	Net electric output plus parasitic and hours loads
Column 1	2	3	4 con't	5 con't	6 con't	7 con't	8 con't	9 con't
Electric Generation	GE	Electric power measured at generator terminals	--	--	--	Measure and convert to mmBtu (-)	Measure (+)	–
	SE	Electric power leaving plant to electric grid	--	--	--	–	--	Measure (+)
	UE	Electric power used internal to a cogenerator or industrial facility for a useful purpose	--	--	--	--	--	Measure (+)
Electric Power Used on Site Not Generated by the Facility	OEO	Electric power coming from grid or other power source to plant during operation	--	--	--	–	--	Measure (-)
	OEN	Electric power coming from grid or other source during non operation	--	--	--	–	–	--
Losses Associated with Generation of Electricity	PE	Parasitic electric loads	--	--	--	–	--	Measure (+)
	HE	House electric loads	--	--	--	–	--	Measure (+)

Table SA-4, Monitoring Cogenerator (CHP) for Net Electric Output and Net Thermal Output under the Simplified Approach								
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Net Thermal Output for Allocation				Net Electric Output	
			Net thermal output measured directly less steam used for electric generation (Primary)	Gross thermal output from exit of steam turbine less parasitic and house loads	Gross thermal output from HRSG/boiler less parasitic and house loads less steam used for electric generation	Measure gross thermal output from HRSG/boiler less parasitic loads, house loads, return feedwater and equivalent electric output expressed in mmBtu.	Net electric output measured directly (Primary)	Gross electric output less parasitic and hours loads
Column 1	2	3	4	5	6	7	8	9
Primary Steam System Note: flow in feedwater return and make up water must equal steam out flow	BSt	Main boiler steam out	--	--	Measure (+)	Measure (+)	–	–
	BFR	Boiler feedwater return	Not monitored under the simplified approach					
	MUW	Make up water	Not monitored under the simplified approach					
Steam Return and Reheat System Note: flow in reheat steam out must equal flow in reheat steam entering boiler	RStO	Reheat steam out	--	Measure (+)	Measure (+)	Measure (+)	–	–
	RStI	Steam returning to boiler for reheating	--	Measure (-)	Measure (-)	Measure (-)	–	--
Steam Used to Generate Electric Power in a Steam Turbine	ESt	Steam entering a turbine	Measure (-)	--	Measure (-)	--	–	–
	XTSt	Steam exhaust from a turbine	--	Measure (+)	--	--	–	--
Useful Thermal Loads	USt	Useful steam entering a process	Measure (+)	--	--	--	--	–
	XSt	Steam or hot water exiting a process	Not monitored under the simplified approach					
	SSt	Steam sold at point of sale	Measure (+)	--	--	--	--	–
	XSt	Return condensate or steam from buyer	Not monitored under the simplified approach					
Losses Associated with Generation of Thermal Output	PSt	Parasitic steam loads	--	Measure (-)	Measure (-)	Measure (-)	–	–
	HSt	House steam loads	--	Measure (-)	Measure (-)	Measure (-)	–	--

Table SA-4, Monitoring Cogenerator (CHP) for Net Electric Output and Net Thermal Output under the Simplified Approach								
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Net Thermal Output for Allocation				Net Electric Output	
			Net thermal output measured directly less steam used for electric generation (Primary)	Gross thermal output from exit of steam turbine less parasitic and house loads	Gross thermal output from HRSG/boiler less parasitic and house loads less steam used for electric generation	Measure gross thermal output from HRSG/boiler less parasitic loads, house loads, return feedwater and equivalent electric output expressed in mmBtu.	Net electric output measured directly (Primary)	Gross electric output less parasitic and hours loads
Column 1	2	3	4 con't	5 con't	6 con't	7 con't	8 con't	9 con't
Electric Generation	GE	Electric power measured at generator terminals	--	--	--	Measure and convert to mmBtu (-)	--	Measure (+)
	SE	Electric power leaving plant to electric grid	--	--	--	--	Measure (+)	–
	UE	Electric power used internal to a cogenerator or industrial facility for a useful purpose	--	--	--	--	Measure (+)	--
Electricity Used on Site Not Generated by the Facility	OEO	Electric power coming from grid or other power source to plant during operation	--	--	--	--	Measure (-)	Measure (-)
	OEN	Electric power coming from grid or other source during non operation	--	--	--	--	–	--
Losses Associated with Generation of Electricity	PE	Parasitic electric loads	--	--	--	--	--	Measure (-)
	HE	House electric loads	--	--	--	--	--	Measure (-)

Table SA-5, Monitoring Cogen (CHP) for Net Electric Output and Gross Thermal Output under the Simplified Approach								
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Gross Thermal Output for Allocation				Net Electric Output	
			Gross thermal output measured directly from exit of steam turbine (Primary)	Gross thermal output measured directly from HRSG/boiler less steam used for electric generation	Net thermal output plus parasitic and house loads less steam used for electric generation	Gross thermal output measured directly from HRSG/boiler less equivalent net electric output in mmBtu.	Net electric output measured directly (Primary)	Gross electric output less parasitic and house loads
Column 1	2	3	4	5	6	7	8	9
Primary Steam System	BSt	Main boiler steam out	--	Measure(+)	--	Measure(+)	--	–
Note: flow in feedwater return and make up water must equal steam out flow	BFR	Boiler feedwater return	Not monitored under the simplified approach					
	MUW	Make up water	Not monitored under the simplified approach					
Steam Return and Reheat System	RStO	Reheat steam out	Measure(+)	Measure(+)	--	Measure(+)	--	–
Note: flow in reheat steam out must equal flow in reheat steam entering boiler	RStI	Steam returning to boiler for reheating	Measure(-)	Measure(-)	--	Measure(-)	--	--
Steam Used to Generate Electric Power in a Steam Turbine	ESt	Steam entering a turbine	--	Measure(-)	–	–	–	–
	XTSt	Steam exhaust from a turbine	Measure (+)	Measure (+)	--	--	–	--
Useful Thermal Loads	USt	Useful steam entering a process	--	--	Measure (+)	--	–	–
	XSt	Steam or hot water exiting a process	Not monitored under the simplified approach					
	SSt	Steam sold at point of sale	--	--	Measure (+)	--	–	–
	XSt	Return condensate or steam from buyer	Not monitored under the simplified approach					
Losses Associated with Generation of Thermal Output	PSt	Parasitic steam loads	--	--	Measure (+)	--	–	–
	HSt	House steam loads	--	--	Measure (+)	--	–	--

Table SA-5, Monitoring Cogen (CHP) for Net Electric Output and Gross Thermal Output under the Simplified Approach									
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Gross Thermal Output for Allocation				Net Electric Output		
			Gross thermal output measured directly from exit of steam turbine (Primary)	Gross thermal output measured directly from HRSG/boiler less steam used for electric generation	Net thermal output plus parasitic and house loads less steam used for electric generation	Gross thermal output measured directly from HRSG/boiler less equivalent net electric output in mmBtu.	Net electric output measured directly (Primary)	Gross electric output less parasitic and house loads
Column 1	2	3	4 con't	5 con't	6 con't	7 con't	8 con't	9 con't
Electric Generation	GE	Electric power measured at generator terminals	--	--	–	Measure and convert to mmBtu (-)	--	Measure (+)
	SE	Electric power leaving plant to electric grid	--	--	–	--	Measure (+)	–
	UE	Electric power used internal to a cogenerator or industrial facility for a useful purpose other than generation of electricity	--	--	–	--	Measure (+)	--
Electric Power Used on Site Not Generated by the Facility	OEO	Electric power coming from grid or other power source to plant during operation	--	--	–	--	Measure (-)	Measure (-)
	OEN	Electric power coming from grid or other source during non operation	--	--	–	--	–	--
Losses Associated with Generation of Electricity	PE	Parasitic electric loads	--	--	–	--	--	Measure (-)
	HE	House electric loads	--	--	–	--	--	Measure (-)

1. *Monitoring Electric Output*

Primary approach: a. Monitoring **net** electric output: A source which is required to monitor net electric output would measure the output in exactly the same manner as described in section VI.B.1., "*Net Electric Output*" (pp. 63-65). (See Table SA-4, columns 8 and 9, pp. 98-99).

Primary approach: b. Measuring **gross** electric output. A source which is required to monitor gross electric output would measure the output in exactly the same manner as described in section VI.B.2., "*Gross Electric Output*" (pp. 65-66). (See Table SA-3, columns 8 and 9, pp. 96-97).

2. *Monitoring **Net** Thermal Output under the Simplified Approach*

It is important to remember that the net thermal output used for allocations is the thermal output used to perform useful work in a process excluding thermal output used to generate electricity. This is referred to as "net thermal output for allocation" to distinguish it from "net thermal output" which includes thermal output used in electric generation. (See Table SA-4, pp. 98-99).

Primary approach: a. Measuring net thermal output directly. A cogeneration facility which is required to determine the net thermal output for allocation may measure the useful thermal output directly. Monitoring net thermal output directly is similar to monitoring net thermal output for allocation for a steam generator, with the additional requirement that thermal energy used to generate electricity would not be included as net thermal output. In general, a company would measure the thermal energy going into each useful process and then calculate the net thermal energy as the sum of the thermal energy going into the useful processes (Table SA-4, column 4).

$$E_{net} = \sum_{\text{Thermal energy for a useful process}} E_{stm}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Thermal energy for a useful process" is the number of places where thermal energy is used to make a product for sale other than electricity or other useful application of steam (excluding generation of steam itself) (Locations USt and SSt in Figures 4, 5, and 6)

Alternative b. Determining net thermal output measuring gross thermal output. A cogeneration or CHP facility which is required to monitor net thermal output, which has an existing gross thermal output system ,and which does not have a system for measuring net output directly may determine the net thermal output as the gross thermal output after the steam turbine and generator less parasitic and house thermal loads (Table SA-4, column 5). (This is appropriate for steam cogenerators and combined cycle cogenerators where thermal energy is used in a process downstream of a steam turbine and generator, as in Figures 4 and 6.)

$$E_{net} = \sum_{\substack{\text{Thermal energy exiting} \\ \text{the steam turbine}}} E_{stm} - \sum_{\text{Parasitic and house thermal loads}} E_{stm}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Thermal energy exiting the steam turbine" is each location where thermal energy leaves a steam turbine that is connected to the unit. (Location XTSt in Figures 4 and 6)

"Parasitic and house thermal loads" is each location where the source measures or determines losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Location HSt and PSt in Figures 4, 5, and 6)

Alternative c. Measuring gross thermal output directly from the boiler less steam for electric generation. For combustion turbine cogenerators, or for the less common situation where some thermal energy is used in a process upstream of a steam turbine and generator, a source might monitor gross thermal output from the boiler, minus the thermal output going to electric generation. In this case, a cogeneration facility which is required to monitor net thermal output and which does not have a system for measuring net output directly may determine the net thermal output as the gross thermal output from the heat recovery steam generator (HRSG) or boiler less house thermal loads, parasitic thermal loads, and boiler feedwater and the steam used for electric generation in a steam turbine and generator (Table SA-4, column 6).

$$E_{net} = \sum_{\text{Boiler thermal energy out}} E_{stm} - \sum_{\text{Parasitic and house thermal loads}} E_{stm} - \sum_{\substack{\text{Thermal energy used} \\ \text{for electric generation}}} E_{stm}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Boiler thermal energy out" is each location where thermal energy leaves the boiler or HRSG. (Location BSt in Figures 4, 5, and 6)

"House and parasitic thermal loads" is each location where the source measures or determines losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Location HSt and PSt in Figures 4, 5, and 6)

"Thermal energy used for electric generation" is each location where thermal energy goes into a steam turbine to operate an electric generator. (Location ESt in Figures 4 and 6)

Alternative (special case)

d. Measuring gross thermal output from boiler less equivalent electric output. For the less common situation where some thermal energy is used in a process upstream of a steam turbine and generator, sources might monitor gross thermal output from the boiler, including thermal output for electric generation. For a cogeneration facility in this situation which is required to determine both net electric output for allocations and net steam for output allocations that does not monitor net output directly, the net thermal output may be determined as follows. The source would measure the gross thermal output from the HRSG or boiler, less the parasitic and house thermal loads, and less the gross electric output from the generator converted to equivalent steam energy using the design steam turbine generator efficiency (See Table SA-4, column 7). Note that when converting electric power to an equivalent steam load to deduct from the net thermal output, a source would convert the gross electric output, not the net electric output, to an equivalent thermal output.

$$E_{net} = \sum_{\text{Boiler thermal energy out}} E_{stm} - \sum_{\text{Parasitic and house thermal loads}} E_{stm} - \sum_{\text{Converted gross electrical output}} E_{elect} \times \frac{3.413}{\text{design turbine efficiency}}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Boiler thermal energy out" is each location where thermal energy leaves the boiler or HRSG. (Location BSt in Figure 4, 5, and 6)

"Parasitic and house thermal loads" is each location where the source measures or determines losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Locations PSt and HSt in Figures 4, 5, and 6)

"Converted electric energy" is the thermal energy for each location where thermal energy goes into a steam turbine to operate an electric generator. It is calculated by "converting" the gross electric output to thermal energy. (Location GE in Figures 4, 5, and 6)

"3.413/Design turbine efficiency" is the conversion factor in mmBtu/MWh, calculated using the manufacturer's design efficiency expressed as a decimal.

3. *Monitoring **Gross** Thermal Output under the Simplified Approach .*

It is important to remember that the gross thermal output used for allocations is the total gross thermal output of the boiler (gross thermal output) less the output used for generation of electricity (we refer to this as "gross thermal output for allocation"). (Thermal energy used to generate electricity will receive an allocation indirectly through the allocation of allowances for electric output.)

Primary approach for steam cogenerators and combined cycle systems:

a. Measuring gross thermal output directly at the exit from a steam turbine: One method for monitoring gross thermal output for allocation would be to measure thermal energy remaining after steam has exited the steam turbine. (This is appropriate for steam cogenerators and combined cycle cogenerators where thermal energy is used in a process downstream of a steam turbine and generator, as in Figures 4 and 6. See Table SA-3, column 4.)

$$E_{allocation} = \sum_{\substack{\text{Thermal energy exiting} \\ \text{the steam turbine}}} \mathrm{E}_{\mathrm{stm}}$$

Where:

$E_{allocation}$ is the gross thermal output for allocation

E_{stm} is the thermal energy in steam or hot water measured at a location

"Thermal energy exiting the steam turbine" is each location where thermal energy leaves a steam turbine that is connected to the unit. (Location XTSt in Figures 4 and 6)

Primary approach for combustion turbine cogenerators:

b. Measuring gross thermal output directly from the boiler less steam for electric generation. For combustion turbine cogenerators, or for the less common situation where some thermal energy is used in a process upstream of a steam turbine and generator, another method for monitoring gross thermal output for allocations may be appropriate. In this case, monitoring gross thermal output for allocation directly would be similar to monitoring gross thermal output for allocation for a steam generator, with the additional requirement that the thermal output used to generate electricity would be deducted from the gross thermal output. (See section VI.C.4., *"Gross Thermal Output under the Boiler Efficiency Approach"*, pp. 87-89, for a description of the basic energy balance approach used.) Deducting the gross thermal energy used to generate electricity may require additional monitoring of the steam used to generate electricity to determine the gross thermal output for allocation (Table SA-3, Column 5, pp. 96-97):

$$E_{allocation} = \sum_{\text{Boiler thermal energy out}} \mathrm{E}_{\mathrm{stm}} - \sum_{\text{Thermal energy used for electrical generation}} E_{stm}$$

Where:

$E_{allocation}$ is the gross thermal output for allocation

E_{stm} is the thermal energy in steam or hot water measured at a location

"Boiler thermal energy out" is each location where thermal energy leaves the boiler or HRSG. (Location BSt in Figures 4, 5, and 6)

"Thermal energy used for electric generation" is each location where thermal energy goes into a steam turbine to operate an electric generator. (Location ESt in Figures 4 and 6)

<u>Alternative</u> c. <u>Determining net thermal output measuring gross thermal output.</u> For a source which has existing net thermal output monitoring installed and which wishes to use this equipment to determine gross thermal output for allocation the company can either: use the monitored net thermal output as an estimate of gross output; or use the monitored thermal output and add any monitored parasitic and house loads to estimate the gross thermal output for allocation (Table SA-3, column 6). We think these are likely options for monitoring thermal output monitoring at cogenerators.

This is particularly true for steam cogenerators and combined cycle cogenerators, since most useful thermal loads are located downstream of the steam turbine and generator.

$$E_{allocation} = \sum_{\text{Thermal energy for a useful process}} E_{stm}$$

or

$$E_{allocation} = \sum_{\text{Thermal energy for a useful process}} E_{stm} + \sum_{\text{Parasitic and house thermal loads}} E_{stm}$$

Where:

$E_{allocation}$ is the gross thermal output for allocation

E_{stm} is the thermal energy in steam or hot water measured at a location

"Thermal energy for a useful process" is the number of places where thermal energy is used to make a product for sale other than electricity (Locations USt or SSt in Figures 4, 5, and 6)

"Parasitic and house thermal loads" is each location where the source measures or determines losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Locations HSt and PSt in Figures 4, 5, and 6)

<u>Alternative</u> d. <u>Measuring gross thermal output from boiler less equivalent electric output.</u> For a source which monitors the gross thermal output and the gross electric output from an electric generator, a simplified option for estimating gross thermal output may be used. (This approach would not apply to a combustion turbine cogenerator, but it could apply to a steam cogenerator or to a combined cycle cogenerator with a secondary electric generator.) A company would estimate the gross thermal output for allocation by monitoring the gross thermal output from the boiler and the electric

output only. Under this approach, the company converts gross electric output to equivalent steam energy using a conversion factor based on the manufacturer's design efficiency for the steam generator. The company would calculate the conversion factor as follows:

$$\text{Steam equivalent} = \left(\frac{3.413 \ \text{mmBtu}/\text{MWh}}{\text{design efficiency, as a decimal}} \right)$$

The company then deducts this energy from the gross thermal output of the boiler. This procedure does not require direct monitoring of the steam loads used to generate power and may simplify monitoring (Table SA-3, column 7). Obviously, this method will not be as exact as measuring the thermal output directly. Therefore, we would not recommend that you allow sources to use this method if they are already measuring the thermal energy going into the steam turbine directly or if they are already measuring the thermal energy for useful processes.

$$E_{allocation} = \sum_{\text{Boiler thermal energy out}} E_{stm} - \sum_{\text{Converted electrical energy}} E_{elect} \times \frac{3.413}{\text{design turbine efficiency}}$$

Where:

$E_{allocation}$ is the gross thermal output for allocation

E_{stm} is the thermal energy in steam or hot water measured at a location

"Boiler thermal energy out" is each location where thermal energy leaves the boiler or HRSG. (Location BSt in Figures 4, 5, and 6)

"Converted electric energy" is the thermal energy for each location where thermal energy goes into a steam turbine to operate an electric generator. It is calculated by "converting" the gross electric output to thermal energy. (Location GE in Figure 4)

"3.413/Design turbine efficiency" is the conversion factor in mmBtu/MWh, calculated using the manufacturer's design efficiency expressed as a decimal.

Monitoring example for a steam cogeneration facility under the simplified approach (see Figure 4, p. 93)

This is an example of a steam boiler cogenerator which generates both electricity and steam. See Tables SA-3 (pp. 96-97), SA-4 (pp. 98-99) and SA-5 (pp. 100-101).

The company could measure or estimate thermal and electric output as follows:

- Primary approach for net electric output: Net electric output for allocation measured directly would be UE+SE-OEO. (Table SA-4, column 8 or Table SA-5, column 8)
- Net electric output for allocation measured as gross electric output less parasitic and house loads would be GE-PE-HE-OEO. (Table SA-4, column 9 or Table SA-5, column 9)
- Primary approach for gross electric output: Gross electric output for allocations measured directly would be GE. (Table SA-3, column 8)
- Gross electric output for allocations estimated as net electric output would be SE+UE-OEO (Table SA-3, column 9)
- Gross electric output for allocation measured as net electric output plus parasitic and house loads would be SE+UE-OEO+PE+HE (Table SA-3, column 9)
- Primary approach for net thermal output: Net thermal output for allocation measured directly would be USt+SSt (Table SA-4, column 4).
- Net thermal output for allocation from cogenerators with process steam used downstream of a steam turbine, determined as gross thermal output from the exit of the steam turbine less parasitic and house loads, would be XTSt-PSt-HSt (Table SA-4, column 5).
- Net thermal output for allocation from cogenerators with process steam used upstream of a steam turbine determined as gross thermal output from the boiler less parasitic and house loads and steam used to generate electricity would be BSt-PSt-HSt-ESt (Table SA-4, column 6).
- Net thermal output for allocation determined as gross thermal output from the boiler less parasitic and house loads and measured gross electric output converted to an equivalent steam output using the conversion factor in mmBtu/MWh would be BSt-PSt-HSt-$GE_{STM\text{-}EQUIV}$

(Table SA-4, column 7).

- Primary approach for gross thermal output: Gross thermal output for allocation measured directly from cogenerators with process steam used downstream of a steam turbine would be XTSt (Table SA-3, column 4, or Table SA-5, column 4)
- Gross thermal output for allocation measured directly from cogenerators with process steam used upstream of a steam turbine or from combustion turbines would be BSt-ESt+XTSt or BSt-ESt, respectively (Table SA-3, column 5, or Table SA-5, column 5)
- Gross thermal output for allocation measured as net thermal output plus parasitic and house loads would be USt+SSt+PSt+HSt (Table SA-3, column 6 or Table SA-5, column 6)
- Gross thermal output for allocation measured as gross thermal output from the boiler less the equivalent steam for a measured gross electric load would be $BSt\text{-}GE_{STM\text{-}EQUIV}$ (Table SA-3, column 7 or Table SA-5, column 7)

Monitoring example for a combustion turbine cogenerator under the simplified approach (see Figure 5, p. 94)

This is an example of a combustion turbine cogenerator which generates both electricity and steam. This cogenerator does not have a steam turbine. See Tables SA-3 (pp. 96-97), SA-4 (pp. 98-99) and SA-5 (pp. 100-101).

The company could measure or estimate thermal and electric output as follows:

- Primary approach for net electric output: Net electric output for allocation measured directly would be UE+SE-OEO. (Table SA-4, column 8 or Table SA-5, column 8)
- Net electric output for allocation measured as gross electric output less parasitic and house loads would be GE-PE-HE-OEO. (Table SA-4, column 9 or Table SA-5, column 9)
- Primary approach for gross electric output: Gross electric output for allocations measured directly would be GE. (Table SA-3, column 8)
- Gross electric output for allocations estimated as net electric output would be SE+UE-OEO (Table SA-3, column 9)
- Gross electric output for allocation measured as net electric output plus parasitic and house loads would be SE+UE-OEO+PE+HE (Table SA-3, column 9)
- Primary approach for net thermal output: Net thermal output for allocation measured directly would be USt+SSt (Table SA-4, column 4).
- Net thermal output for allocation from combustion turbines determined as gross thermal output from the boiler less parasitic and house loads would be BSt-PSt-HSt (Table SA-4, column 6).
- Primary approach for gross thermal output: Gross thermal output for allocation measured directly from combustion turbines would be BSt-ESt (Table SA-3, column 5, or Table SA-5, column 5)
- Gross thermal output for allocation measured as net thermal output plus parasitic and house loads would be USt+SSt+PSt+HSt (Table SA-3, column 6 or Table SA-5, column 6)

Monitoring example for a combined cycle cogeneration facility under the simplified approach. (See Figure 6, p. 95)

This is an example of a combined cycle cogenerator which generates both electricity and steam. See Tables SA-3 (pp. 96-97), SA-4 (pp. 98-99) and SA-5 (pp. 100-101).

The company could measure or estimate thermal and electric output as follows:

- Primary approach for net electric output: Net electric output for allocation measured directly would be UE+SE-OEO. (Table SA-4, column 8 or Table SA-5, column 8)
- Net electric output for allocation measured as gross electric output less house and parasitic losses would be GE-PE-HE-OEO. (Table SA-4, column 9 or Table SA-5, column 9)
- Primary approach for gross electric output: Gross electric output for allocations measured directly would be GE. (Table SA-3, column 8)
- Gross electric output for allocations estimated as net electric output would be SE+UE-OEO (Table SA-3, column 9)
- Gross electric output for allocation measured as net electric output plus parasitic and house loads would be SE+UE-OEO+PE+HE (Table SA-3, column 9)
- Primary approach for net thermal output: Net thermal output for allocation measured directly would be USt+SSt (Table SA-4, column 4).
- Net thermal output for allocation from cogenerators with process steam used downstream of a steam turbine, determined as gross thermal output from the exit of the steam turbine less parasitic and house loads, would be XTSt-PSt-HSt (Table SA-4, column 5).
- Net thermal output for allocation from cogenerators with process steam used upstream of a steam turbine determined as gross thermal output from the HRSG less parasitic and house loads and steam used to generate electricity would be BSt-PSt-HSt-ESt (Table SA-4, column 6).
- Net thermal output for allocation determined as gross thermal output from the boiler less parasitic and house loads and measured gross electric output converted to an equivalent steam output using a conversion factor in mmBtu/MWh would be BSt-PSt-HSt-$GE_{STM\text{-}EQUIV}$ (Table SA-4, column 7).
- Primary approach for gross thermal output: Gross thermal output for allocation measured

directly from cogenerators with process steam used downstream of a steam turbine would be XTSt (Table SA-3, column 4, or Table SA-5, column 4)

- Gross thermal output for allocation measured directly from cogenerators with process steam used upstream of a steam turbine would be BSt-ESt+XTSt (Table SA-3, column 5, or Table SA-5, column 5)
- Gross thermal output for allocation measured as net thermal output plus parasitic and house loads would be USt+SSt+PSt+HSt (Table SA-3, column 6 or Table SA-5, column 6)
- Gross thermal output for allocation measured as gross thermal output from the boiler less the equivalent steam for a measured gross electric load would be $BSt\text{-}GE_{STM\text{-}EQUIV}$ (Table SA-3, column 7 or Table SA-5, column 7)

Figure 4
Steam Cogenerator

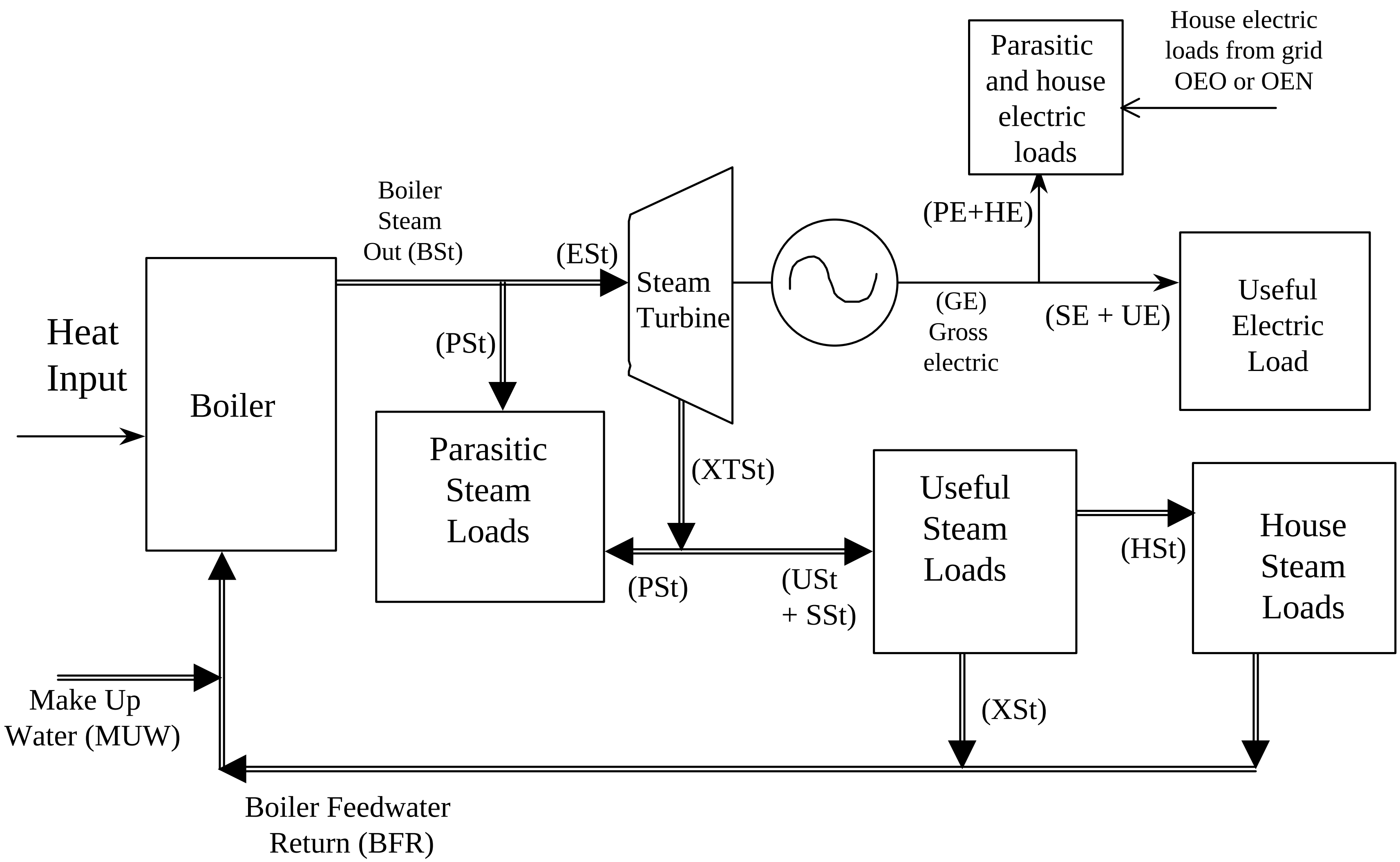

Figure 5
Combustion Turbine Cogenerator

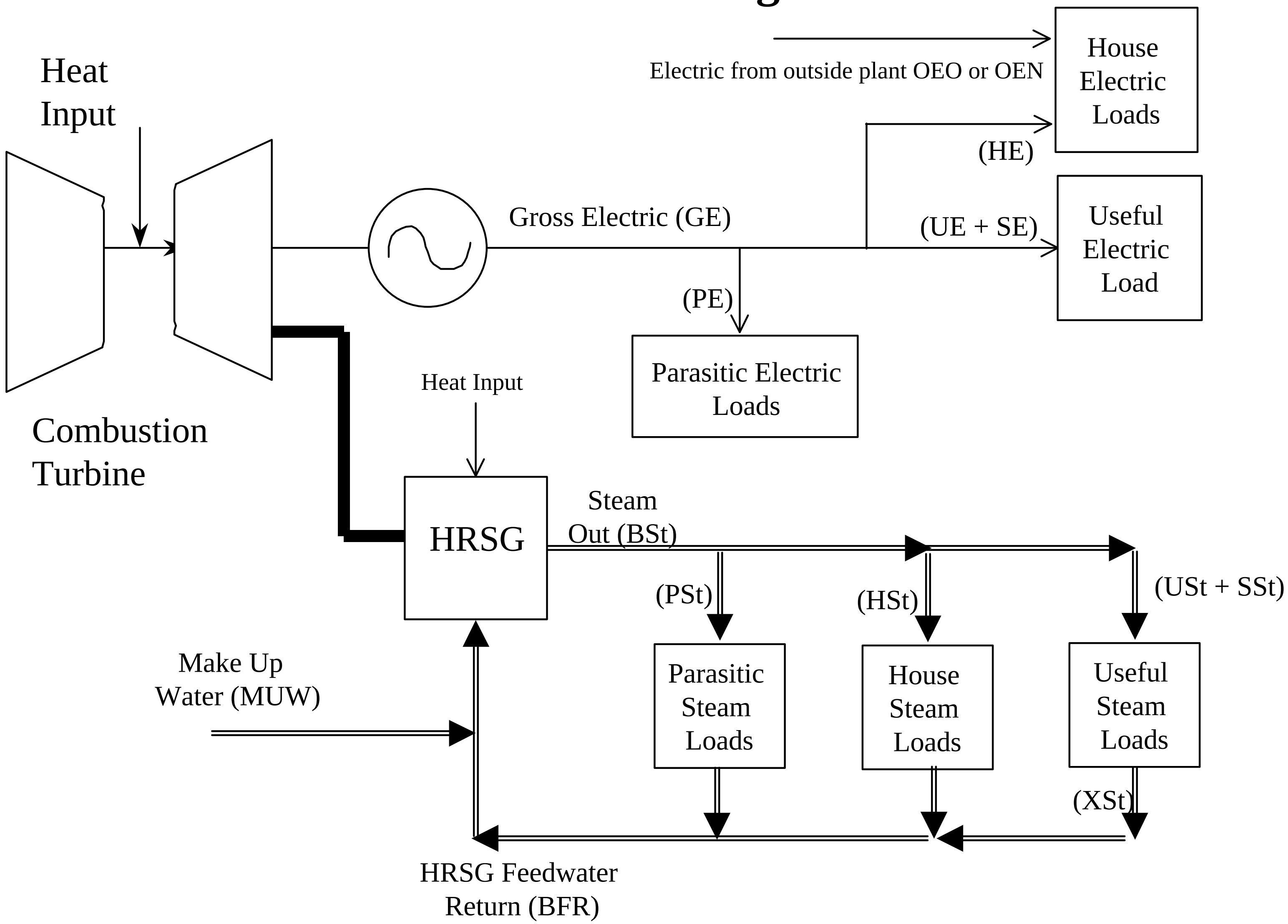

Figure 6
Combined Cycle Cogenerator

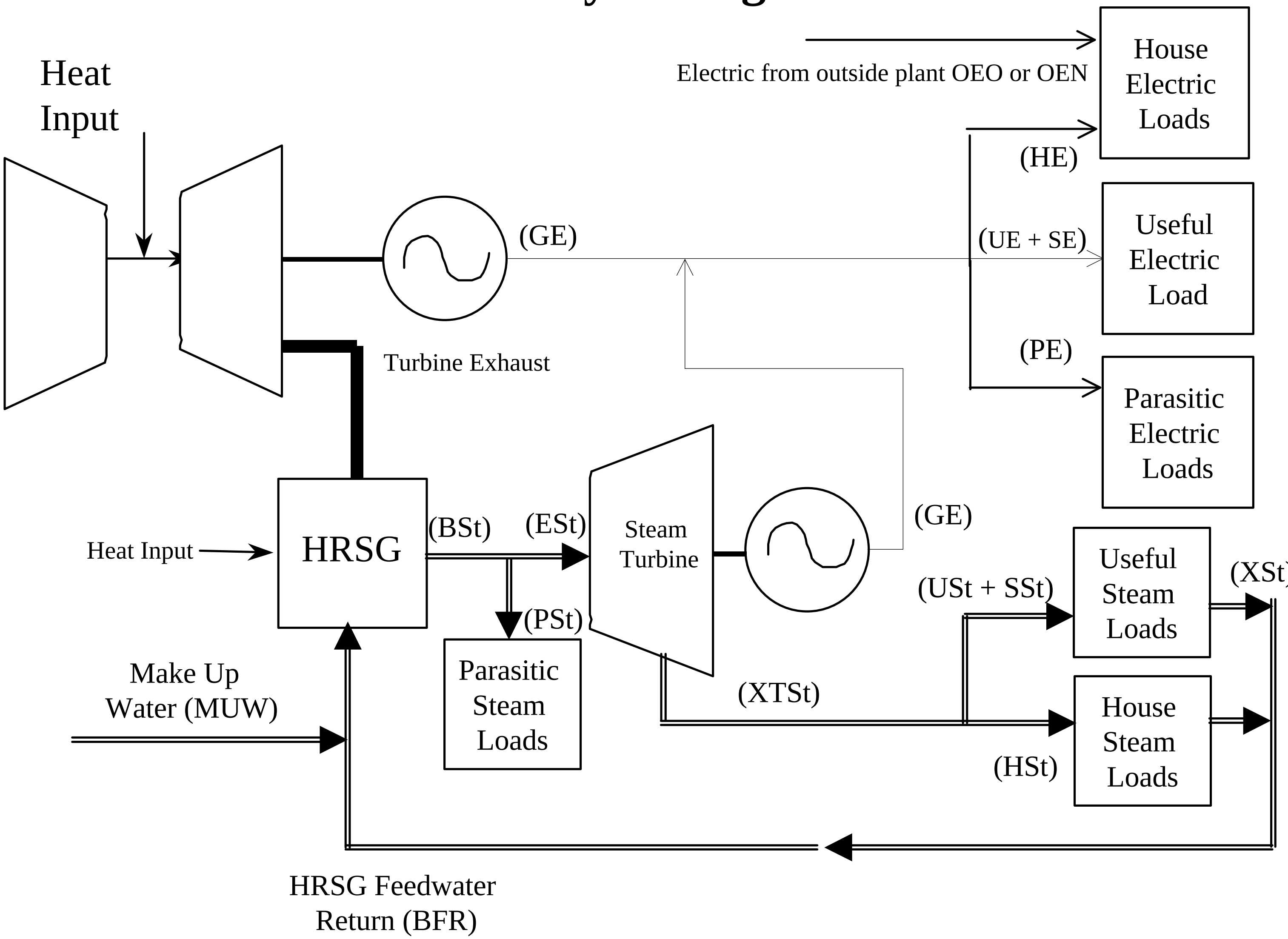

Table BE-3, Monitoring Cogenerator for Gross Electric Output and Gross Thermal Output under the Boiler Efficiency Approach

Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Gross Thermal Output for Allocation				Gross Electric Output	
			Gross thermal output measured directly at exit from steam turbine	Gross thermal output measured directly at HRSG/boiler less steam used for electric generation	Net thermal output plus parasitic and house loads less steam used for electric generation	Gross thermal output measured directly at HRSG/boiler less equivalent electric output in mmBtu.	Gross electric output measured directly	Net electric output plus parasitic and hours loads
Column 1	2	3	4	5	6	7	8	9
Primary Steam System Note: flow in feedwater return and make up water must equal steam out flow	BSt	Main boiler steam out	--	Measure(+)	--	Measure(+)	--	--
	BFR	Boiler feedwater return	Measure(-)	Measure(-)	Measure (-)	Measure(-)	--	–
	MUW	Make up water	Measure(-)	Measure(-)	Measure (-)	Measure(-)	--	--
Steam Return and Reheat System Note: flow in reheat steam out must equal flow in reheat steam entering boiler	RStO	Reheat steam out	Measure(+)	Measure(+)	--	Measure(+)	--	--
	RStI	Steam returning to boiler for reheating	Measure(-)	Measure(-)	--	Measure(-)	--	--
Steam Used to Generate Electric Power in a Steam Turbine	ESt	Steam entering a turbine	--	Measure(-)	--	--	--	--
	XTSt	Steam exhaust from a turbine	Measure (+)	Measure (+)	--	--	--	--
Useful Thermal Loads	USt	Useful steam or hot water entering a process	--	--	Measure (+)	--	--	--
	XSt	Steam or hot water exiting a process	--	--	--	--	--	--
	SSt	Steam sold at point of sale	--	--	Measure (+)	--	--	--
	XSt	Return condensate or steam from buyer	--	--	--	--	--	--
Losses Associated with Generation of Thermal Output	PSt	Parasitic steam loads	--	--	Measure (+)	--	--	--
	HSt	House steam loads	--	--	Measure (+)	--	--	--

Table BE-3, Monitoring Cogenerator for Gross Electric Output and Gross Thermal Output under the Boiler Efficiency Approach								
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Gross Thermal Output for Allocation				Gross Electric Output	
			Gross thermal output measured directly at exit from steam turbine (Primary)	Gross thermal output measured directly at HRSG/boiler less steam used for electric generation	Net thermal output plus parasitic and house loads less steam used for electric generation	Gross thermal output measured directly at HRSG/boiler less equivalent electric output in mmBtu.	Gross electric output measured directly (Primary)	Net electric output plus parasitic and hours loads
Column 1	2	3	4 (con't)	5 (con't)	6 (con't)	7 (con't)	8 (con't)	9 (con't)
Electric Generation	GE	Electric power measured at generator terminals	--	--	--	Measure and convert to mmBtu (-)	Measure (+)	–
	SE	Electric power leaving plant to electric grid	--	--	--	–	--	Measure (+)
	UE	Electric power used internal to a cogenerator or industrial facility for a useful purpose	--	--	--	--	--	Measure (+)
Electric Power Used on Site Not Generated by the Facility	OEO	Electric power coming from grid or other power source to plant during operation	--	--	--	–	--	Measure (-)
	OEN	Electric power coming from grid or other source during non operation	--	--	--	–	–	--
Losses Associated with Generation of Electricity	PE	Parasitic electric loads	--	--	--	–	--	Measure (+)
	HE	House electric loads	--	--	--	–	--	Measure (+)

Table BE-4, Monitoring Cogenerator (CHP) for Net Electric Output and Net Thermal Output under the Boiler Efficiency Approach

Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Net Thermal Output for Allocation				Net Electric Output	
			Net thermal output measured directly less steam used for electric generation (Primary)	Gross thermal output from exit of steam turbine less parasitic and house loads	Gross thermal output from HRSG/boiler less parasitic and house loads less steam used for electric generation	Measure gross thermal output from HRSG/boiler less parasitic loads, house loads, return feedwater and equivalent electric output expressed in mmBtu.	Net electric output measured directly (Primary)	Gross electric output less parasitic and hours loads
Column 1	2	3	4	5	6	7	8	9
Primary Steam System	BSt	Main boiler steam out	--	--	Measure (+)	Measure (+)	–	–
Note: flow in feedwater return and make up water must equal steam out flow	BFR	Boiler feedwater return	Measure (-)	Measure (-)	Measure (-)	Measure (-)	--	–
	MUW	Make up water	Measure (-)	Measure (-)	Measure (-)	Measure (-)	--	--
Steam Return and Reheat System	RStO	Reheat steam out	--	Measure (+)	Measure (+)	Measure (+)	–	–
Note: flow in reheat steam out must equal flow in reheat steam entering boiler	RStI	Steam returning to boiler for reheating	--	Measure (-)	Measure (-)	Measure (-)	–	--
Steam Used to Generate Electric Power in a Steam Turbine	ESt	Steam entering a turbine	Measure (-)	--	Measure (-)	--	–	–
	XTSt	Steam exhaust from a turbine	--	Measure (+)	--	--	–	--
Useful Thermal Loads	USt	Useful steam entering a process	Measure (+)	--	--	--	--	–
	XSt	Steam or hot water exiting a process	--	--	--	--	--	–
	SSt	Steam sold at point of sale	Measure (+)	--	--	--	--	–
	XSt	Return condensate or steam from buyer	--	--	--	--	--	--
Losses Associated with Generation of Thermal Output	PSt	Parasitic steam loads	--	Measure (-)	Measure (-)	Measure (-)	–	–
	HSt	House steam loads	--	Measure (-)	Measure (-)	Measure (-)	–	--

Table BE-4, Monitoring Cogenerator (CHP) for Net Electric Output and Net Thermal Output under the Boiler Efficiency Approach									
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Net Thermal Output for Allocation				Net Electric Output		
			Net thermal output measured directly less steam used for electric generation (Primary)	Gross thermal output from exit of steam turbine less parasitic and house loads	Gross thermal output from HRSG/boiler less parasitic and house loads less steam used for electric generation	Measure gross thermal output from HRSG/boiler less parasitic loads, house loads, return feedwater and equivalent electric output expressed in mmBtu.	Net electric output measured directly (Primary)	Gross electric output less parasitic and hours loads	
Column 1	2	3	4 (con’t)	5 (con’t)	6 (con’t)	7 (con’t)	8 (con’t)	9 (con’t)	
Electric Generation	GE	Electric power measured at generator terminals	--	--	--	Measure and convert to mmBtu (-)	--	Measure (+)	
	SE	Electric power leaving plant to electric grid	--	--	--	--	Measure (+)	–	
	UE	Electric power used internal to a cogenerator or industrial facility for a useful purpose	--	--	--	--	Measure (+)	--	
Electricity Used on Site Not Generated by the Facility	OEO	Electric power coming from grid or other power source to plant during operation	--	--	--	--	Measure (-)	Measure (-)	
	OEN	Electric power coming from grid or other source during non operation	--	--	--	--	–	--	
Losses Associated with Generation of Electricity	PE	Parasitic electric loads	--	--	--	--	--	Measure (-)	
	HE	House electric loads	--	--	--	--	--	Measure (-)	

Table BE-5, Monitoring Cogen (CHP) for Net Electric Output and Gross Thermal Output under the Boiler Efficiency Approach								
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Gross Thermal Output for Allocation				Net Electric Output	
			Gross thermal output measured directly from exit of steam turbine (Primary)	Gross thermal output measured directly from HRSG/boiler less steam used for electric generation	Net thermal output plus parasitic and house loads less steam used for electric generation	Gross thermal output measured directly from HRSG/boiler less equivalent net electric output in mmBtu.	Net electric output measured directly (Primary)	Gross electric output less parasitic and house loads
Column 1	2	3	4	5	6	7	8	9
Primary Steam System	BSt	Main boiler steam out	--	Measure(+)	--	Measure(+)	--	–
Note: flow in feedwater return and make up water must equal steam out flow	BFR	Boiler feedwater return	Measure(-)	Measure(-)	Measure (-)	Measure(-)	--	–
	MUW	Make up water	Measure(-)	Measure(-)	Measure (-)	Measure(-)	--	--
Steam Return and Reheat System	RStO	Reheat steam out	Measure(+)	Measure(+)	--	Measure(+)	--	–
Note: flow in reheat steam out must equal flow in reheat steam entering boiler	RStI	Steam returning to boiler for reheating	Measure(-)	Measure(-)	--	Measure(-)	--	--
Steam Used to Generate Electric Power in a Steam Turbine	ESt	Steam entering a turbine	--	Measure(-)	–	–	–	–
	XTSt	Steam exhaust from a turbine	Measure (+)	Measure (+)	--	--	–	--
Useful Thermal Loads	USt	Useful steam entering a process	--	--	Measure (+)	--	–	–
	XSt	Steam or hot water exiting a process	--	--	--	--	–	–
	SSt	Steam sold at point of sale	--	--	Measure (+)	--	–	–
	XSt	Return condensate or steam from buyer	--	--	--	--	–	--
Losses Associated with Generation of Thermal Output	PSt	Parasitic steam loads	--	--	Measure (+)	--	–	–
	HSt	House steam loads	--	--	Measure (+)	--	–	--

Table BE-5, Monitoring Cogen (CHP) for Net Electric Output and Gross Thermal Output under the Boiler Efficiency Approach									
Overall System Description In this column are the various systems associated with boilers and electric generators as defined in the diagrams	Possible Monitoring Locations In this column are the specific points which might need to be monitored under different approaches. The letter in the first column corresponds to letters used on the associated diagrams		Gross Thermal Output for Allocation				Net Electric Output	
			Gross thermal output measured directly from exit of steam turbine (Primary)	Gross thermal output measured directly from HRSG/boiler less steam used for electric generation	Net thermal output plus parasitic and house loads less steam used for electric generation	Gross thermal output measured directly from HRSG/boiler less equivalent net electric output in mmBtu.	Net electric output measured directly (Primary)	Gross electric output less parasitic and house loads
Column 1	2	3	4 (con't)	5 (con't)	6 (con't)	7 (con't)	8 (con't)	9
Electric Generation	GE	Electric power measured at generator terminals	--	--	–	Measure and convert to mmBtu (-)	--	Measure (+)
	SE	Electric power leaving plant to electric grid	--	--	–	--	Measure (+)	–
	UE	Electric power used internal to a cogenerator or industrial facility for a useful purpose other than generation of electricity	--	--	–	--	Measure (+)	--
Electric Power Used on Site Not Generated by the Facility	OEO	Electric power coming from grid or other power source to plant during operation	--	--	–	--	Measure (-)	Measure (-)
	OEN	Electric power coming from grid or other source during non operation	--	--	–	--	–	--
Losses Associated with Generation of Electricity	PE	Parasitic electric loads	--	--	–	--	--	Measure (-)
	HE	House electric loads	--	--	–	--	--	Measure (-)

4. *Monitoring **Net** Thermal Output under the Boiler Efficiency Approach.*

It is important to remember that the net thermal output used for allocations is the thermal output used to perform useful work in a process only, not thermal output used to generate electricity. This is referred to as "net thermal output for allocation" to distinguish it from "net thermal output" which includes thermal output used in electric generation.

Primary approach: (a) Measuring net thermal output directly. A cogeneration (CHP) facility which is required to determine the net thermal output for allocation may measure the useful thermal output directly. Monitoring net thermal output directly is similar to monitoring net thermal output for allocation for a steam generator, with the additional requirement that thermal energy used to generate electricity would not be included as net thermal output. In general, a company would measure the thermal energy going into and out of each useful process and then calculate the net thermal energy as the sum of the differences between the thermal energy going into the useful processes and exiting the useful processes (Table BE-4, column 4, pp. 120-121).

$$E_{net} = \sum_{\text{Thermal energy for a useful process}} E_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Thermal energy for a useful process" is the number of places where thermal energy is used to make a product for sale other than electricity (Locations USt and SSt in Figures 4, 5, and 6)

"Thermal energy returning to boiler" is where thermal energy returns to the boiler or HRSG, such as in the boiler feedwater return. (Location BFR in Figures 4, 5, and 6)

Alternative b. Determining net thermal output measuring gross thermal output. A cogeneration or CHP facility which is required to monitor net thermal output which has an existing gross thermal output system and which does not have a system for measuring net output directly may determine the net thermal output as the gross thermal output after the steam turbine and generator less house thermal loads, parasitic thermal loads, and boiler feedwater return (Table BE-4, column 5). (This is appropriate for steam cogenerators and combined cycle cogenerators with process steam used downstream of a steam turbine and generator, as in Figures 4 and 6.)

$$E_{net} = \sum_{\substack{\text{Thermal energy exiting} \\ \text{the steam turbine}}} E_{stm} - \sum_{\text{Parasitic and house thermal loads}} E_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Thermal energy exiting the steam turbine" is each location where thermal energy leaves a steam turbine that is connected to the unit. (Location XTSt in Figures 4 and 6)

"House and parasitic thermal loads" is each location where the source measures or determines losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Location HSt and PSt in Figures 4, 5, and 6)

"Thermal energy returning to boiler" is where thermal energy returns to the boiler or HRSG, such as in the boiler feedwater return. (Location BFR in Figures 4, 5, and 6)

<u>Alternative</u> c. <u>Measuring gross thermal output directly from the boiler less steam for electric generation.</u> For combustion turbine cogenerators, or for the less common situation where some thermal energy is used in a process upstream of a steam turbine and generator, a source might monitor gross thermal output from the boiler, minus the thermal output going to electric generation. In this case, a cogeneration (CHP) facility which is required to monitor net thermal output which does not have a system for measuring net output directly may determine the net thermal output as the gross thermal output from the HRSG or boiler less house thermal loads, parasitic thermal

loads, and boiler feedwater and the steam used for electric generation in a steam turbine and generator (Table BE-4, column 6).

$$E_{net} = \sum_{\text{Boiler thermal energy out}} E_{stm} - \sum_{\text{Parasitic and house thermal loads}} E_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm} - \sum_{\substack{\text{Thermal energy used} \\ \text{for electric generation}}} E_{stm}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Boiler thermal energy out" is each location where thermal energy leaves the boiler or HRSG. (Location BSt in Figures 4, 5, and 6)

"House and parasitic thermal loads" is each location where the source measures or determines losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Location HSt and PSt in Figures 4, 5, and 6)

"Thermal energy returning to boiler" is where thermal energy returns to the boiler or HRSG, such as in the boiler feedwater return. (Location BFR in Figures 4, 5, and 6)

"Thermal energy used for electric generation" is each location where thermal energy goes into a steam turbine to operate an electric generator. (Location ESt in Figures 4 and 6)

Alternative (special case):

d. Measuring gross thermal output from boiler less equivalent electric output. For the less common situation where some thermal energy is used in a process upstream of a steam turbine and generator, sources might monitor gross thermal output from the boiler, including thermal output for electric generation. (This approach would not apply to a combustion turbine cogenerator, but it could apply to a steam cogenerator or to a combined cycle cogenerator with a secondary electric generator.) For a cogeneration (CHP) facility in this situation which is required to determine both net electric output for allocations and net steam for output allocations and which does not monitor net output directly, the net thermal output may be determined as follows. The source would measure the gross thermal output from the HRSG or boiler, less the parasitic and house loads, the boiler feedwater return and less the gross electric output from the generator converted to equivalent steam energy using the design steam turbine generator efficiency (See Table BE-4, column 7, pp. 120-121). Note that when converting electric power to an equivalent steam load to deduct from the net thermal output, a source would convert the gross electric output, not the net electric output, to an equivalent thermal output. Obviously, this method will not be as exact as measuring the thermal output directly. Therefore, we would not recommend that you allow sources to use this method if they are already measuring the thermal energy going into the steam turbine directly or if they are already measuring the thermal energy for useful processes.

$$E_{net} = \sum_{\text{Boiler thermal energy out}} E_{stm} - \sum_{\text{Parasitic and house thermal loads}} E_{stm} - \sum_{\substack{\text{Thermal energy}\\ \text{returning to boiler}}} E_{stm} - \sum_{\text{Converted gross electrical output}} E_{elect} \times \frac{3.413}{\text{design turbine efficiency}}$$

Where:

E_{net} is the net thermal output

E_{stm} is the thermal energy in steam or hot water measured at a location

"Boiler thermal energy out" is each location where thermal energy leaves the boiler or HRSG. (Location BSt in Figure 4, 5, and 6)

"Parasitic and house thermal loads" is each location where the source measure or determine losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Locations PSt and HSt in Figures 4, 5, and 6)

"Thermal energy returning to boiler" is where thermal energy returns to the boiler or HRSG, such as in the boiler feedwater return. (Location BFR in Figures 4, 5, and 6)

"Converted electric energy" is the thermal energy for each location where thermal energy goes into a steam turbine to operate an electric generator. It is calculated by "converting" the gross electric output to thermal energy. (Location GE in Figures 4, 5, and 6)

"3.413/Design turbine efficiency" is the conversion factor in mmBtu/MWh, calculated using the manufacturer's design efficiency expressed as a decimal.

5. *Monitoring **Gross** Thermal Output under the Boiler Efficiency Approach*.

For a cogeneration or combined heat and power (CHP) facility required to monitor both gross thermal output and gross electric output, the monitoring locations are described in Table BE-3 (pp. 118-119). It is important to remember that the gross thermal output used for allocations is the total gross thermal output of the boiler (gross thermal output) less the output used for generation of electricity (we refer to this as "gross thermal output for allocation"). (Thermal energy used to generate electricity will receive an allocation indirectly through the allocation of allowances for electric output.)

Primary approach for steam cogenerators or combined cycle systems:

a. Measuring gross thermal output directly at the exit from a steam turbine: One method for monitoring gross thermal output for allocation would be to measure thermal energy remaining after steam has exited the steam turbine. (This is a common configuration for steam cogenerators and combined cycle cogenerators that use process steam downstream of a steam turbine and generator, as in Figures 4 and 6. See Table BE-3, column 4.)

$$E_{allocation} = \sum_{\substack{\text{Thermal energy exiting} \\ \text{the steam turbine}}} \mathrm{E}_{\mathrm{stm}} - \sum_{\text{Thermal energy returning to boiler}} E_{stm}$$

Where:

$E_{allocation}$ is the gross thermal output for allocation

E_{stm} is the thermal energy in steam or hot water measured at a location

"Thermal energy exiting the steam turbine" is each location where thermal energy leaves a steam turbine that is connected to the unit. (Location XTSt in Figures 4 and 6)

"Thermal energy returning to boiler" is where thermal energy returns to the boiler or HRSG, such as in the boiler feedwater return. (Location BFR in Figures 4, 5, and 6)

Primary approach for combustion turbine cogenerators:

b. Measuring gross thermal output directly from the boiler less steam for electric generation. For combustion turbine cogenerators, or for the less common situation where some thermal energy is used in a process upstream of a steam turbine and generator, another method for monitoring gross thermal output for allocations may be appropriate. In this case, monitoring gross thermal output for allocation directly would be similar to monitoring gross thermal output for allocation for a steam generator, with the additional requirement that the thermal output used to generate electricity would be deducted from the gross thermal output. (See section VI.C.4, *"Gross Thermal Output under the Boiler Efficiency Approach"*, pp. 87-89, for a description of the basic energy balance approach used.) Deducting the gross thermal energy used to generate electricity may require additional monitoring of the steam used to generate electricity to determine the gross thermal output for allocation (Table BE-3, Column 5, pp. 118-119):

$$E_{allocation} = \sum_{\text{Boiler thermal energy out}} \mathrm{E}_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm} - \sum_{\text{Thermal energy used for electrical generation}} E_{stm}$$

Where:

$E_{allocation}$ is the gross thermal output for allocation

E_{stm} is the thermal energy in steam or hot water measured at a location

"Boiler thermal energy out" is each location where thermal energy leaves the boiler or HRSG. (Location BSt in Figures 4, 5, and 6)

"Thermal energy returning to boiler" is where thermal energy returns to the boiler or HRSG, such as in the boiler feedwater return. (Location BFR in Figures 4, 5, and 6)

"Thermal energy used for electric generation" is each location where thermal energy goes into a steam turbine to operate an electric generator. (Location ESt in Figures 4 and 6)

Alternative c. Determining net thermal output measuring gross thermal output. For a source which has existing net thermal output monitoring installed and which wishes to use this equipment to determine gross thermal output for allocation the company can either: use the monitored net thermal output as an estimate of gross output; or use the monitored thermal output and add any monitored parasitic and house loads to estimate the gross thermal output for allocation (Table BE-3, column 6). We think these are likely options for monitoring thermal output monitoring at cogenerators. This is particularly true for steam cogenerators and combined cycle cogenerators, since most useful thermal loads are located downstream of the steam turbine and generator.

$$E_{allocation} = \sum_{\text{Thermal energy for a useful process}} E_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm}$$

or

$$E_{allocation} = \sum_{\text{Thermal energy for a useful process}} E_{stm} + \sum_{\text{Parasitic and house thermal loads}} E_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm}$$

Where:

$E_{allocation}$ is the gross thermal output for allocation

E_{stm} is the thermal energy in steam or hot water measured at a location

"Thermal energy for a useful process" is the number of places where thermal energy is used to make a product for sale other than electricity (Locations USt or SSt in Figures 4, 5, and 6)

"Parasitic and house thermal loads" is each location where the source measures or determines losses of thermal energy from parasitic (auxiliary) or house thermal loads. (Locations HSt and PSt in Figures 4, 5, and 6)

"Thermal energy returning to boiler" is where thermal energy returns to the boiler or HRSG, such as in the boiler feedwater return. (Location BFR in Figures 4, 5, and 6)

Alternative d. Measuring gross thermal output from boiler less equivalent electric output. For a source which monitors the gross thermal output and the gross electric output, a simplified option for estimating gross thermal output may be used. (This approach would not apply to a combustion turbine cogenerator, but it could apply to a steam cogenerator or to a combined cycle cogenerator with a secondary electric generator.) A company would estimate the gross thermal output for allocation by monitoring the gross thermal output from the boiler and the electric output only. Under this approach, the company converts gross electric output to equivalent steam energy using a conversion factor based on the manufacturer's design efficiency for the steam turbine generator. The company would calculate the conversion factor as follows:

$$\text{Steam equivalent} = \left(\frac{3.413 \ \text{mmBtu}/\text{MWh}}{\text{design efficiency, as a decimal}} \right)$$

The company then deducts this energy from the gross thermal output of the boiler. This procedure does not require direct monitoring of the steam loads used to generate power and may simplify monitoring (Table BE-3, column 7). Obviously, this method will not be as exact as measuring the thermal output directly. Therefore, we would not recommend that you allow sources to use this method if they are already measuring the thermal energy going into the steam turbine directly or if they are already measuring the thermal energy for useful processes.

$$E_{allocation} = \sum_{\text{Boiler thermal energy out}} E_{stm} - \sum_{\text{Thermal energy returning to boiler}} E_{stm} - \sum_{\text{Converted electrical energy}} E_{elect} \times \frac{3.413}{\text{design turbine efficiency}}$$

Where:

$E_{allocation}$ is the gross thermal output for allocation

E_{stm} is the thermal energy in steam or hot water measured at a location

"Boiler thermal energy out" is each location where thermal energy leaves the boiler or HRSG. (Location BSt in Figures 4, 5, and 6)

"Thermal energy returning to boiler" is where thermal energy returns to the boiler or HRSG, such as in the boiler feedwater return. (Location BFR in Figures 4, 5, and 6)

"Converted electric energy" is the thermal energy for each location where thermal energy goes into a steam turbine to operate an electric generator. It is calculated by "converting" the gross electric output to thermal energy. (Location GE in Figure 4)

"3.413/Design turbine efficiency" is the conversion factor in mmBtu/MWh, calculated using the manufacturer's design efficiency expressed as a decimal.

<u>Monitoring example for a steam cogeneration facility under the boiler efficiency approach (see Figure 4, p. 115)</u>

This is an example of a steam boiler cogenerator which generates both electricity and steam. See Tables BE-3 (pp. 118-119), BE-4 (pp. 120-121), and BE-5 (pp. 122-123).

The company could measure or estimate thermal and electric output as follows:

- <u>Primary approach for net electric output:</u> Net electric output for allocation measured directly would be UE+SE-OEO. (Table BE-4, column 8 or Table BE-5, column 8)
- Net electric output for allocation measured as gross electric output less parasitic and house loads would be GE-PE-HE-OEO. (Table BE-4, column 9 or Table BE-5, column 9)
- <u>Primary approach for gross electric output:</u> Gross electric output for allocations measured directly would be GE. (Table BE-3, column 8)
- Gross electric output for allocations estimated as net electric output would be SE+UE-OEO (Table BE-3, column 9)
- Gross electric output for allocation measured as net electric output plus parasitic and house loads would be SE+UE-OEO+PE+HE (Table BE-3, column 9)
- <u>Primary approach for net thermal output:</u> Net thermal output for allocation measured directly would be USt+SSt-BFR-MUW (Table BE-4, column 4).
- Net thermal output for allocation from cogenerators with process stream used downstream of a steam turbine, determined as gross thermal output from the exit of the steam turbine less parasitic and house loads, would be XTSt-BFR-MUW-PSt-HSt (Table BE-4, column 5).
- Net thermal output for allocation from cogenerators with process steam used upstream of a steam turbine determined as gross thermal output from the boiler less parasitic and house loads and steam used to generate electricity would be BSt-BFR-MUW-PSt-HSt-ESt (Table BE-4, column 6).
- Net thermal output for allocation determined as gross thermal output from the boiler less parasitic and house loads and measured gross electric output converted to an equivalent steam output using the conversion factor in mmBtu/MWh would be BSt-BFR-MUW-PSt-HSt-$GE_{STM\text{-}EQUIV}$ (Table BE-4, column 7).
- <u>Primary approach for gross thermal output:</u> Gross thermal output for allocation measured

directly from most cogenerators with steam turbines would be XTSt-BFR-MUW (Table BE-3, column 4, or Table BE-5, column 4)

- Gross thermal output for allocation measured directly from cogenerators with process steam used upstream of a steam turbine or from combustion turbines would be BSt-BFR-MUW-ESt+XTSt or BSt-BFR-MUW-ESt, respectively (Table BE-3, column 5, or Table BE-5, column 5)
- Gross thermal output for allocation measured as net thermal output plus parasitic and house loads would be USt+SSt+PSt+HSt-BFR-MUW (Table BE-3, column 6 or Table BE-5, column 6)
- Gross thermal output for allocation measured as gross thermal output from the boiler less the equivalent steam for a measured gross electric load would be BSt-BFR-MUW-$GE_{STM-EQUIV}$ (Table BE-3, column 7 or Table BE-5, column 7)

Monitoring example for a combustion turbine cogenerator under the boiler efficiency approach (see Figure 5, p. 116)

This is an example of a combustion turbine cogenerator which generates both electricity and steam. This cogenerator does not have a steam turbine. See Tables BE-3 (pp. 118-119), BE-4 (pp. 120-121), and BE-5 (pp. 122-123).

The company could measure or estimate thermal and electric output as follows:

- Primary approach for net electric output: Net electric output for allocation measured directly would be UE+SE-OEO. (Table BE-4, column 8 or Table BE-5, column 8)
- Net electric output for allocation measured as gross electric output less parasitic and house loads would be GE-PE-HE-OEO. (Table BE-4, column 9 or Table BE-5, column 9)
- Primary approach for gross electric output: Gross electric output for allocations measured directly would be GE. (Table BE-3, column 8)
- Gross electric output for allocations estimated as net electric output would be SE+UE-OEO (Table BE-3, column 9)
- Gross electric output for allocation measured as net electric output plus parasitic and house loads would be SE+UE-OEO+PE+HE (Table BE-3, column 9)
- Primary approach for net thermal output: Net thermal output for allocation measured directly would be USt+SSt-BFR-MUW (Table BE-4, column 4).
- Net thermal output for allocation from combustion turbines determined as gross thermal output from the boiler less parasitic and house loads would be BSt-BFR-MUW-PSt-HSt (Table BE-4, column 6).
- Primary approach for gross thermal output: Gross thermal output for allocation measured directly from combustion turbines would be BSt-BFR-MUW-ESt, (Table BE-3, column 5, or Table BE-5, column 5)
- Gross thermal output for allocation measured as net thermal output plus parasitic and house loads would be USt+SSt+PSt+HSt-BFR-MUW (Table BE-3, column 6 or Table BE-5, column 6)

Monitoring example for a combined cycle cogeneration facility under the boiler efficiency approach. (See Figure 6, p. 117)

This is an example of a combined cycle cogenerator which generates both electricity and steam. See Tables BE-3 (pp. 118-119), BE-4 (pp. 120-121), and BE-5 (pp. 122-123).

The company could measure or estimate thermal and electric output as follows:

- Primary approach for net electric output: Net electric output for allocation measured directly would be UE+SE-OEO. (Table BE-4, column 8 or Table BE-5, column 8)
- Net electric output for allocation measured as gross electric output less house and parasitic losses would be UE+SE-PE-HE-OEO. (Table BE-4, column 9 or Table BE-5, column 9)
- Primary approach for gross electric output: Gross electric output for allocations measured directly would be GE. (Table BE-3, column 8)
- Gross electric output for allocations estimated as net electric output would be SE+UE-OEO (Table BE-3, column 9)
- Gross electric output for allocation measured as net electric output plus parasitic and house loads would be SE+UE-OEO-PE+HE (Table BE-3, column 9)
- Primary approach for net thermal output: Net thermal output for allocation measured directly would be USt+SSt-BFR-MUW (Table BE-4, column 4).
- Net thermal output for allocation from cogenerators with process steam used downstream of a steam turbine, determined as gross thermal output from the exit of the steam turbine less parasitic and house loads, would be XTSt-BFR-MUW-PSt-HSt (Table BE-4, column 5).
- Net thermal output for allocation from cogenerators with process steam used upstream of a steam turbine determined as gross thermal output from the HRSG less parasitic and house loads and steam used to generate electricity would be BSt-BFR-MUW-PSt-HSt-ESt (Table BE-4, column 6).
- Net thermal output for allocation determined as gross thermal output from the boiler less parasitic and house loads and measured gross electric output converted to an equivalent steam output using a conversion factor in mmBtu/MWh would be BSt-BFR-MUW-PSt-HSt-$GE_{STM\text{-}EQUIV}$ (Table BE-4, column 7).
- Primary approach for gross thermal output: Gross thermal output for allocation measured

directly from cogenerators with process steam used downstream of a steam turbine would be XTSt-BFR-MUW (Table BE-3, column 4, or Table BE-5, column 4)

- Gross thermal output for allocation measured directly from cogenerators with process steam used upstream of a steam turbine would be BSt-BFR-MUW-ESt+XTSt (Table BE-3, column 5, or Table BE-5, column 5)
- Gross thermal output for allocation measured as net thermal output plus parasitic and house loads would be USt+SSt+PSt+HSt-BFR-MUW (Table BE-3, column 6 or Table BE-5, column 6)
- Gross thermal output for allocation measured as gross thermal output from the boiler less the equivalent steam for a measured gross electric load would be BSt-BFR-MUW-$GE_{STM\text{-}EQUIV}$ (Table BE-3, column 7 or Table BE-5, column 7)

E. How do I calculate output data from supporting data?

Thermal output

You can calculate the thermal energy or thermal output of a stream of steam or hot water as follows:

$$E_{stm}(mmBtu) = H\left(\frac{mmBtu}{lb}\right) \times Q(lb)$$

Where:

E_{stm} = total thermal energy in steam or water for an hour
H = enthalpy from standard thermodynamic steam table
Q = total mass flow of steam or water for an hour

If you have a flowmeter that measures the volume of steam or water instead of the mass, you will also need to know the density or specific volume. You can find this information in steam tables for saturated steam if you know the pressure or the temperature. Mass flow equals the volumetric flow multiplied by the density.

To use the equation above, you will need to determine the enthalpy using a steam table. Here is an example of how you would determine the enthalpy of <u>saturated</u> steam or hot water. You can expect steam to be saturated in most industrial or institutional boilers. You will need to use the absolute pressure of the steam or hot water, a measured value. For saturated steam, the temperature is determined by the pressure. Below are example entries from ASME's steam tables in English units. (The metric units are EC and K, kPa, cm^3/kg, and kJ/kg.) Of the columns in the table, the ones you need to be concerned about are the columns for temperature, absolute pressure, and enthalpy. Typically, you will only need to use the column for the enthalpy of water or the column for the total enthalpy of steam. (The column "Evap" refers to the enthalpy or latent heat needed to heat water at the boiling point until it becomes steam at the boiling point, but you probably won't need to use this column.)

If you knew you had warm water and a source's measurements gave an absolute pressure reading of 0.5 psia, then the enthalpy of the warm water would be 47.62 Btu/lb. You would use this enthalpy value in the equation above to calculate the energy in the water.

In another case, you have an absolute pressure reading of 200 psia. In this case, you will determine the enthalpy of the steam from the table as 1198.3 Btu/lb of steam. Determining enthalpy for steam is a more common case than determining enthalpy for hot water.

Table VI-2: Saturated Steam Table (Excerpt)

Abs. Pressure	Temp- erature	Specific Volume V (ft^3/lb)			Enthalpy H (Btu/lb)			Entropy S (Btu/lb•EF)			Internal Energy U (Btu/lb)	
psia	EF	Water	Evap.	Steam	Water	Evap.	Steam	Water	Evap.	Steam	Water	Steam
0.0886	32.018	0.01602	3302.4	3302.4	0.00	1075.5	1075.5	0	2.1872	2.1872	0	1021.3
0.5	79.586	0.01607	641.5	641.5	**47.62**	1048.6	1096.3	0.0925	1.9446	2.0370	47.62	1036.9
14.696	212	0.01672	26.782	26.80	180.17	970.3	1150.5	0.3121	1.4447	1.7568	180.12	1077.6
200	381.80	0.01839	2.2689	2.287	355.5	842.8	**1198.3**	0.5438	1.0016	1.5454	354.8	1113.7

Table VI-3: Superheated Steam Table (Excerpt)

Abs. Press. (psia)	Property	Temperature, EF									
(sat. temp, EF)		100	200	300	400	500	600	700	800	900	1000
1	V (ft^3/lb)	0.0161	392.5	452.3	511.9	571.5	631.1	690.7	___	___	___
(101.74)	H (Btu/lb)	68.0	1150.2	1195.7	1241.8	1288.6	1336.1	1384.5	___	___	___
	S (Btu/lbCEF)	0.1295	2.0509	2.1152	2.1722	2.2237	2.2708	2.3144	___	___	___
15	V (ft^3/lb)	0.0161	0.0166	29.899	33.963	37.985	41.986	45.978	49.964	53.946	57.926
(213.03)	H (Btu/lb)	68.0	168.09	1192.5	**1239.9**	1287.3	1335.2	1383.8	1433.2	1483.4	1534.5
	S (Btu/lbCEF)	0.1295	0.2940	1.8134	1.8720	1.9242	1.9717	2.0155	2.0563	2.0946	2.1309
200	V (ft^3/lb)	0.0161	0.0166	0.0174	2.3598	2.7247	3.0583	3.3783	3.6915	4.0008	4.3077
(381.80)	H (Btu/lb)	68.52	168.51	269.96	1210.1	1269.0	1322.6	1374.3	1425.5	1477.0	1529.1
	S (Btu/lbCEF)	0.1294	02938	0.4369	1.5593	1.6242	1.6776	1.7239	1.7663	1.8057	1.8426
2000	V (ft^3/lb)	0.0160	0.0165	0.0173	0.0184	0.0201	0.0233	0.2488	0.3072	0.3534	0.3642
(635.80)	H (Btu/lb)	73.26	172.60	273.32	377.19	487.53	614.48	1240.9	**1353.4**	1408.7	1474.1
	S (Btu/lbCEF)	0.1283	0.2916	0.4337	0.5621	0.6834	0.8091	1.3794	1.4578	1.5138	1.5603

Here are two examples of how you would determine the enthalpy of superheated steam (also called "supersaturated steam") using a steam table. You will need to use the measured temperature and absolute pressure of the steam. Note that there are a number of possible temperatures for a particular pressure.

In the first example, a stream of superheated steam has a pressure of 15 psi and a temperature of 400EF, as measured with pressure and temperature transmitters. Its enthalpy from the table, H, is 1239.9 Btu/lb.

In the second example, a stream of superheated steam at a pressure of 2000 psi and a temperature of 800EC has an enthalpy of 1353.4 Btu/lb. Now you can multiply this value by the mass flow of steam to determine the total energy in the steam.

Electric output

Many companies use watt-meters that measure electric power generation directly in MW. In some cases, sources use current and potential transformers to monitor electric output. These will measure current in amperes and potential in volts, rather than directly measuring electric power generation in MW. One can calculate power from current and potential using the following equation:

$$P = I \cdot V$$

Where,

P is the power in megawatts, (MW)

I is the current in amperes (A), and

V is the potential in volts (V).

One can then calculate the MW-hr generation by multiplying the MW value by the length of time for which it is measured.

VII. Requirements for Sources: How should sources monitor, record, and report output data to support updating output-based allocations?

If you intend to write your own requirements for companies to monitor, record and report output data, there are a number of issues for you to consider. They are discussed in this section.

Conventional power plants will measure, and will receive allocations based on, electric output. These conventional power plants will not need to measure any additional thermal energy for the purposes of supporting data for allocations, because the conventional power plants use thermal energy to produce electricity, rather than for other useful purposes. Industrial or institutional boilers and turbines that do not generate electricity will measure, and will receive allocations based on, thermal output. These industrial or institutional boilers and turbines will not need to measure any additional electric output for the purposes of supporting data for allocations.

Facilities that produce both electricity and steam or hot water as useful outputs will need to measure both thermal and electric output. Most of these are cogeneration facilities, also called combined heat and power (CHP) facilities. Cogeneration facilities tend to be more efficient because they produce thermal output and electric output in sequence, from the same heat input. In order to determine net output, facilities producing both kinds of output will need to account for parasitic and house loads for both electricity and steam or hot water. Cogeneration facilities can be classified either as electric generating units or as non-electric generating units, depending on the characteristics of the unit and the associated generator.

A. What might my State require to ensure that individual sources monitor and report consistent and accurate output data?

You need to develop a procedure to ensure that output monitoring and reporting are performed in a clear and consistent manner. For NOx emissions data, the monitoring and reporting provisions under Part 75, Subpart H specify the requirements which ensure that the data collected are consistent and accurate. As monitoring of output data is simply another type of monitoring, you can apply to output monitoring, when appropriate, the existing processes under Part 75 designed to ensure consistent and accurate monitoring. This will promote both consistent and accurate data and a more cost-effective compliance process. Where feasible, you should incorporate output monitoring into the existing framework of Part 75, Subpart H monitoring requirements that you are using to ensure that emissions are accurately monitored.

Below is a list of the major steps in emissions monitoring which are designed to ensure consistent and accurate emissions monitoring. Later in section VII.B, "How detailed or prescriptive should output monitoring and reporting requirements be in my State rule?" (pp. 144-150), we suggest three different means of incorporating output monitoring into these existing processes.

- Monitoring Plan Review Process: Each source must submit a monitoring plan which describes how emissions (and possibly output) will be monitored. You will review each monitoring plan. The primary function of the monitoring plan review process is to allow you to ensure that each source is monitoring in a manner consistent with other similar sources in the trading program.
- Installation of Monitoring Equipment: This step is necessary if the company has not already installed monitoring equipment that can meet regulatory requirements.
- Certification Test Protocol Process: Once a company has determined how it will monitor and has a reviewed monitoring plan, it submits a test protocol for review. The test protocol describes how all monitoring systems will be certified. The primary function of the certification test protocol is to allow regulators to ensure that the testing approach will meet the requirements for certification. For emission monitors, certification requirements are set forth under Part 75.
- Certification Application and Approval Process: Once a source has a reviewed testing protocol and performs the required certification testing, the NOx authorized account representative submits the results of the testing for approval. The primary function of the certification application and review process is to allow you to ensure that each source has passed the required certifications tests and has a monitoring system capable of meeting the accuracy requirements in Part 75. While there are exceptions, collected data generally can be invalidated retroactively until the initial certification application is approved.
- Ongoing QA/QC Procedures: Once a monitor passes the initial certification, it must also continue to pass different quality assurance (QA) tests and the company must perform quality control (QC) activities. The primary function of ongoing QA/QC

procedures is to ensure that the monitoring systems are not neglected so that accuracy remains high over the life of the system. Sources must report the results of QA/QC.

- Missing Data Substitution During Monitor Outage: For a certified emissions monitoring system which does not pass a required QA test, data are considered invalid or missing during the time period that lasts from the end of the failed test until corrective maintenance has been performed and the required QA test has been passed for a the monitoring system. A company must substitute emissions data during the period of missing data. Additionally, if an emissions monitoring system malfunctions and fails to collect data due to a problem or needs maintenance while a unit is operating, the use of missing data substitution is required during this period.

You may include all or only some of these requirements in your output monitoring rule. In the next section, we lay out three different options which use some or all of the procedures above for output monitoring.

B. How detailed or prescriptive should output monitoring and reporting requirements be in my State rule?

Here are three options for how a regulator could approach establishing requirements for monitoring, recording, and reporting output data. These three options differ in how detailed and extensive requirements are. Each option will require a different level of effort for regulators and for companies and will result in a different level of quality assurance on the output data.

<u>Option #1 The Detailed Monitoring Option</u>.

Monitoring emissions includes the basic steps outlined above in the previous section, namely, monitoring plan review, certification test protocol review, certification test results approval, ongoing QA/QC procedures and reporting of results, hourly and summary output data reporting, and missing data substitution for a monitoring system outage. You could choose to apply this approach to monitoring output. If you choose this option, you should do the following:

- Specify what type of output must be monitored and by which sources (for example, net electric output and net thermal output from electric generating units).
- Define the monitoring and reporting requirements in your State rule. This would include

monitor location procedures, certification test protocol requirements, accuracy requirements for initial certification tests, ongoing QA/QC procedures, reporting procedures, missing data substitution procedures, and procedures for failure to comply with the above requirements.

- Require each affected source to submit a hardcopy output monitoring plan for State review. See section VII.F., "What should a source be required to report in a monitoring plan?" (pp. 153-155) for a description of what a monitoring plan would contain. Although Part 75 requires companies to submit monitoring plans no later than 45 days before beginning a certification test, we recommend that companies should submit monitoring plans at least a year prior to the date which output monitoring is required. Experience gained in implementing the Acid Rain Program and the OTC NOx Budget program indicate that few initial monitoring plan submissions are 100% error-free. Thus, you should plan on having to comment on and request resubmission of the monitoring plans. The monitoring plan review process may require several cycles of submission, review and comment and resubmission before a facility's monitoring plan is acceptable. If a source has not already submitted a monitoring plan for emission monitoring equipment, it should incorporate the portion of the monitoring plan on output monitoring equipment into the monitoring plan for emission monitoring equipment. If a source has already submitted a monitoring plan for emissions monitoring, then the submission should be treated as an update to the hardcopy portion of the monitoring plan.
- Require each affected source to submit a hardcopy test protocol for State review. In general, a test protocol would describe in detail the standards and procedures used to certify equipment. See section VII.G., "What Certification, Quality Assurance and Quality Control procedures should be required for output monitoring?" (pp. 155-161) for a description of tests, standards or procedures which would be included in a test protocol. An output monitoring equipment test protocol should be required to be included with the certification test protocol for emission monitoring equipment at the source unless the emissions monitoring test protocol has already been submitted. Some States require companies to wait for approval of their test protocols before proceeding with testing. However, this is not a requirement of Part 75. If you intend to do this, you must add such a requirement in your

State rule.

- Require each affected source to submit an initial certification application for each output monitoring system for your approval.
- Require each affected source to submit ongoing QA/QC test results for output monitoring equipment to you. You will need to devise a methodology for sources to report the QA/QC test results for output monitoring equipment outside the electronic format used for reporting emissions data to EPA.
- Require each affected source to record and report output data. Under this option, a source would record hourly data. If any data were missing or invalid, the source would perform missing data substitution on an hourly basis. As the current electronic reporting format does not fully support reporting output data, you would have to devise your own data reporting procedure.

Some of the issues which arise if you choose to follow this option are:

- This is a proven method of collecting good data and will provide a high level of confidence that no source under-reports or over-reports output data.
- This methodology ensures that all sources are monitoring in a consistent manner so that all output data is equivalent.
- This option contains built-in incentives to continually ensure that the output data collected are valid. The primary incentive is the substitution of unfavorable values when monitors malfunction or fail routine QA tests.
- Reporting of hourly data allows you a high level of detailed information for data analysis for errors.
- The regulated community is accustomed to this option under the Acid Rain Program and the OTC NOx Budget Program.
- This option can have additional costs for you and for sources that are associated with implementation and ongoing reporting of output data. In particular there are costs associated with new data collection and reporting requirements, monitoring plan development, certification testing, and ongoing QA/QC.
- You may have limited resources for reviewing ongoing QA/QC data. A resource intensive

option might be a problem given the limited resources available. In particular the monitoring plan review process, certification application review process, and hourly data quality assurance process are resource-intensive for an agency.

Option #2 The Simplified Option

The simplest regulatory option would be to only require reporting of output data with no associated monitoring methodologies or quality assurance requirements. This option, which is currently used in the Acid Rain Program to collect gross hourly output in MWh or klb steam, is associated with a lower level of effort on the part of regulatory agencies and provides the lowest assurance of quality data of the three options. (Note that output data do not play a major role in the Acid Rain Program, which does not allocate allowances based on output.) Under this option, you would need to do the following:

- Specify what type of output must be monitored and by which sources (for example, net electric output and net thermal output from electric generating units).
- Specify the requirements for reporting data to you. The output data should be calculated from hourly data and reported in hourly, daily, weekly, or monthly format.
- The source does not need to file an output monitoring plan, testing protocol, certification application, or QA/QC test results for output monitoring equipment.

Carefully review the following list of issues related to this option:

- This option has the lowest assurance of the three options that data reported are accurate.
- This is the easiest option for any sources which already have output monitoring systems.
- This option has the lowest assurance of the three options that output monitoring is consistent. There is little or no standardization of output monitoring under this option.
- This option does not address at all what a source should do if it does not have output data.
- There would be no means available to require sources which over-report output to correct either their monitoring option or any data which are clearly erroneous, as no requirements exist.
- This is the simplest and least resource-intensive option.

Option #3 The Intermediate Option

In this intermediate option, you would require consistent monitoring and QA/QC through the monitoring plan submission and review process. You would reduce the oversight on certification and ongoing QA/QC testing from Option #1 by simply requiring that a source document the QA/QC plan for the output monitoring system in its monitoring plan. You could also allow the data collection and reporting requirements to be somewhat less prescriptive than that for monitoring emissions. Under this option, a source would simply submit an output monitoring plan which describes the monitoring methodology used, the initial and ongoing QA/QC test procedures, the data recording procedures, and any provisions which will be used for filling in missing data. Under this option, you would specify the output monitoring system accuracy. The source would prepare a document which describes an output monitoring option designed to meet the accuracy requirement on a system basis. You could require that this document be prepared by a qualified professional engineer and could require that the NOx authorized account representative sign a statement indicating he or she certifies that the system meets or exceeds the accuracy requirement. At a minimum, the "output quality assurance plan" would meet the requirements under the monitoring plan contents (see section VII.F., "What should a source be required to report in a monitoring plan?", pp. 153-155) and would describe the QA/QC activities under section VII.G., "What Certification, Quality Assurance and Quality Control procedures should be required for output monitoring?" (pp. 155-161).

Under this option, sources would submit the QA/QC plan for review and approval. You would have flexibility to require periodic QA/QC testing to ensure that the output system is actually monitoring output accurately.

Your State rule would clearly define the QA/QC plan approval requirements. It would further indicate the steps your State would take if the output data were suspected of being inaccurate. You would have to do the following to implement this option:

- Specify what type of output must be monitored and by which sources.
- Specify the system accuracy of output monitoring systems.
- Require that sources submit a monitoring plan for your approval. The monitoring plan includes the necessary data to provide assurance that the source is monitoring in an

acceptable fashion and is performing adequate QA/QC on the output monitoring system.

- Require each affected source to record output data and report the data to you in a specified manner and format.
- Provide provisions in your rule which allow you to audit and require changes in output monitoring if the system does not meet the accuracy requirement.

Some of the issues which arise if you choose to follow Option #3 are:

- This approach could give reasonable assurance that data reported are accurate.
- This is an easy option for any sources that already have output monitoring systems.
- You would be able to audit and require a source to follow the QA/QC plan if you suspect that a source is not reporting output correctly.
- This is a simpler option that the traditional Part 75 approach for emissions.
- It gives you some ability to ensure that the output monitoring generally is consistent and acceptable. Because you will accomplish this through case-by-case monitoring plan review, not through regulations, the effort may be more difficult and more resource intensive than under Option #1.
- Missing data substitution procedures are addressed by sources, although they would not necessarily be consistent from one source to another.
- This option provides sources with much greater flexibility in designing a system which meets the accuracy requirement.

  Other options exist for you to consider.

Choosing Between Options #1, #2, #3 and Other Options.

The fundamental reason we use Option #1 (the detailed approach) for pollutant emissions is to ensure consistent and accurate pollution emissions data. The level of agency oversight in using this approach is necessitated by the need to ensure environmental protection and to ensure that emissions remain below the level of the "emissions cap". This approach relies heavily on the incentives provided through the use of missing data substitution procedures and the required QA/QC provisions to ensure accurate data with any errors being conservative (that is, environmentally protective) in nature. The missing data substitution procedures under Part 75 for emissions use a progressive approach where the values are near or at the average emissions when a monitor has a history of few outages, and the values are at the maximum potential emission when a monitor outage lasts over an extended period.

Output monitoring is different than emissions monitoring in that, while some ancillary environmental benefits may result from allocating through output, the "cap" on emissions is fixed and any error in output would not result in emission exceeding the "cap". Because of this difference, it may not be necessary to require the same level of agency oversight and required QA/QC for output monitoring as that required under Option #1 (the detailed monitoring approach).

Another difference between emissions monitoring and output monitoring is that each source potentially has an interest in ensuring that other sources do not overestimate their output. This is due to the fact that if one source in a State under a fixed budget for allowance allocations overstates its output and therefore receives additional allowances, the additional allowances it receives comes at the expense of other sources in the State.

C. What output measurement equipment must affected facilities use?

The equipment for monitoring electric output is already in place, is in most cases monitored consistently, and in most cases is sufficiently accurate; thus, this part of monitoring presents relatively few problems for the State wishing to create a rule for monitoring output. Monitoring thermal output presents more problems as the monitoring is not performed consistently, the equipment has varying degrees of accuracy, and in some cases the equipment necessary to monitor output with a sufficient degree of accuracy is not currently installed. Additionally, sources may not necessarily monitor output at a location that corresponds to the location where you want to allocate NOx allowances. Electric generating systems that are not fossil fuel-fired can measure electric output as described in this section for electric generating units. See section VII.G., "What Certification, Quality Assurance and Quality Control procedures should be required for output monitoring?" (pp. 155-161) for a discussion about monitoring technologies and their accuracy.

D. When must facilities start measuring output?

Sources would need to measure and record output-related information no later than May 1 of the year four years before the first year for which you plan to update allocations based on output data. For example, if you intend to update allowance allocations for the year 2006 using output, sources would need to measure and record output data beginning no later than May 1, 2002. You then would be able to calculate and allocate allowances in the year 2003, consistent with the NOx Budget Trading Program procedure of allocating NOx allowances at least three years ahead.

E. What records must affected facilities keep and report to support output-based allocations?

The records a facility must keep and report depends on the monitoring option you choose (Options #1, #2, or #3 from section VII.B. "How detailed or prescriptive should output monitoring and reporting requirements be in my State rule?", pp. 144-150), the monitoring approach (the simplified approach or the boiler efficiency approach to monitoring thermal output from section VI., "Where could facilities monitor electric and thermal output?", pp. 55-141), and the data collection frequency you specify.

Monitoring Plan

See section VII.F., "What should a source be required to report in a monitoring plan?" for a description of information to be reported in a monitoring plan (pp. 153-155).

Data Reported to the State

The first issue you should resolve is whether output data you receive should be raw hourly data, or should be some summary data (daily, weekly monthly or ozone season totals) based on hourly records. While other options exist, data that is based on hourly values recorded in a datalogger or computer and kept as records is consistent with the current monitoring requirements and is also consistent with the data used for sales of electric and steam. Because of these reasons, we recommend that hourly data be either reported or kept as records for at least three years from the date of the record's creation.

Under Option #1 for monitoring and reporting (the detailed option) you would probably require reporting of hourly data and some summary values. Monthly or ozone season output values will give you the data you need for allocations. If you require data to be reported for each hour, you may want to have companies report for calendar quarters so that you do not need to review data from an entire ozone season at once. Under Options #2 and #3 (the simplified option and the intermediate option), you would likely get ozone season or monthly output data. In this case, it may be easier for you to require a single report at the end of the ozone season, unless companies already are sending you quarterly reports for other requirements. Under all options, we believe that you should require that the data reported be calculated from hourly data. This is because reporting hourly data will be consistent with sales data and because we believe that hourly data captures the variability of output processes sufficiently to ensure accurate data. For example, thermal output data are calculated from measurements of steam or water flow rate, temperature, and pressure information, which vary over the course of an hour.

We recommend that you require facilities that receive output-based allocations to keep records of hourly data and totals for the ozone season for electric generation and thermal output. Companies should keep this information for each location (unit or generator or facility) where the output is measured. You also could request the supporting data kept on site (or at the company's offices) . You also could decide if you want net output data, gross output data, or both.

Output information

For each electric generating unit, for each non-emitting electric generating system, or for each plant:

- Keep hourly records of the gross or net electric generation in MWh.

For each electric generation unit that cogenerates and for each non-electric generating unit that produces steam:

- Keep hourly records of the net or gross thermal output, in mmBtu$_{out}$. (See section VI.E., "How do I calculate output data from supporting data?", pp. 138-141, for how to calculate thermal output.)
- Keep hourly records of the steam pressure, temperature and calculated enthalpy, in mmBtu$_{out}$. (See section VI.E, "How do I calculate output data from supporting data?", pp. 138-141, for how to calculate enthalpy.)
- Keep hourly records of the net or gross steam flow rate after steam has been diverted for generating any electricity, in thousands of pounds of steam per hour (klb/hr).
- Keep hourly pressure (psi) and temperature (EF) readings for any location that is not under saturated steam conditions.
- Keep hourly pressure (psi) readings for any location under saturated steam conditions.

These records may be kept on site or at a corporate office, provided that the company can provide these records to inspectors during the day of an inspection or audit.

Quality assurance and certification test data

If you choose Option #1 for monitoring output (the detailed option), you will need to require both reporting and record keeping for QA/QC test results. The test results should include:

- Descriptions of the standard used to test the equipment, e.g., NIST traceable, ANSI C12.16, IEEE 57.13
- Actual values recorded or determined under each test.
- Tables or calculations if necessary to compute accuracy.
- Results of the test, pass or fail.
- Date and time of test.

F. What should a source be required to report in a monitoring plan?

Output Monitoring Plan

If you decide to require that sources submit an output monitoring plan, we suggest that the description of the output monitoring system be included in the hardcopy monitoring plan submitted for emission monitoring system approval.

Under Option #1

If you choose to use Option #1 for monitoring and reporting (the detailed option) or if you choose to use Option #3 for monitoring and reporting (the intermediate option) , you would probably require sources to submit an output monitoring plan. The descriptions should include at a minimum the following information.

- A diagram of the electrical or steam system for which output is being monitored.
- If you require monitoring of gross electric output, the diagram should contain all affected units and all generators served by each affected unit and the relationship of units to generators. If a generator served by an affected unit is also served by a non-affected unit, the non-affected unit and its relationship to each generator should be indicated on the diagram as well. The diagram should indicate where the gross electric output is measured.
- If you require monitoring of gross thermal output, the diagram should include all input energy streams and output energy streams connected to each boiler. For a complex situation, this would be all streams to and from a group of boilers which serve a common steam system. This would include steam out, boiler feedwater return, and make-up water energy

streams. The diagram should include estimated average flow rates in lb/hr so that a mass balance of all streams may be performed which satisfies the law of conservation of mass (e.g., the sum of all input streams in lb/hr = the sum of all exit streams in lb/hr) In addition, each steam will have an estimated temperature, pressure and phase indicator (L = liquid, S = saturated steam, SS = superheated steam) and an enthalpy estimate in Btu/lb. The diagram will also indicate all flow meters, temperature or pressure sensors, or other equipment used to calculate gross thermal output.

- If you require monitoring of net electric output, the diagram should contain all affected units and all generators served by each affected unit and the relationship of units to generators. If a generator served by an affected unit is also served by a non-affected unit, the non-affected unit and its relationship to each generator should be indicated on the diagram as well. The diagram should indicate where the net electric output is measured and should include all electrical inputs and outputs from to plant. If net electric output is determined using a billing meter, the diagram should show the billing meters used to determine net sales of electricity and should show that all electricity measured at the point of sale is generated by affected units.
- If you require monitoring of net thermal output, the diagram should include all steam or hot water coming into the net steam system, including steam from affected and non-affected units, and all exit points of steam or hot water from the net steam system. In addition, each input and output stream will have an estimated temperature, pressure and phase indicator (L = liquid, S = saturated steam, SS = superheated steam) and an enthalpy in Btu/lb. The net steam system should identify all useful loads, house loads, parasitic loads, any other steam loads and all boiler feedwater return. The diagram will represent all energy losses in the system as either usable or usable losses. The diagram will also indicate all flow meters, temperature or pressure sensors or other equipment used to calculate gross thermal output. If a sales agreement is used to determine net thermal output, the diagram should show the monitoring equipment used to determine the sales of steam.

The monitoring plan should provide a description of each output monitoring system. The description of the output monitoring system should include a written description of the output system, the equations used to calculate output. For net thermal output systems descriptions and justifications of each useful load should be included.

The monitoring plan should provide a description and a data flow diagram of how data from each component of the output system is collected and how the data is transferred to the data acquisition and handling system for determining output. This is not necessary for billing meters used to determine output, if you intend to let a company report the information from its billing data records. In that case, it may be more appropriate for the monitoring plan to show the flow of data from the billing meter to the company's system for collecting and recording data from the billing meter.

Under Option #3

If you choose to use Option #3 for monitoring and reporting (the intermediate option), you should also require the NOx authorized account representative (NOx AAR) to submit the following additional information in the monitoring plan:

- A detailed description of all quality assurance quality control activities which will be performed to maintain the output system. In the case where billing meters are used to determine output, you do not need to require QA/QC activities beyond what the company already performs. Also, current transformers and potential transformers do not require QA/QC testing, and thus do not need a list of QA/QC procedures in their monitoring plan.
- A certification statement by a professional engineer stating that the output monitoring system meets an accuracy of 10% of the reference value, or that each component monitor for output meets an accuracy of 3% of the full scale value with the engineer's stamp and the certification of the NOx AAR that this is true.

G. What Certification, Quality Assurance and Quality Control procedures (QA/QC) should be required for output monitoring?

Initial certification of accuracy

If you choose to require initial certification of output monitoring systems, we suggest that sources send an initial certification of the accuracy of their output measurement equipment to their permitting authority no later than May 1, 2002. This will give sources time to verify the accuracy of their equipment before the recording of data (i.e., prior to the ozone season in 2002) that will be used to develop allowance allocations for the year 2006 under the Part 96 model rule. If you choose to start allowance allocations based upon output after the year 2006, sources would need to certify the accuracy of their output measurement equipment no later than May 1 of the year that is four years before the year for which you first allocate NOx allowances using output data.

Any output measurement equipment used as a billing meter in commercial transactions does not require certification or testing requirements. To qualify as a billing meter, the measurement device must be used to measure electric or thermal output for commercial billing under a contract. The facility where the measurement device is located must have different owners from the owners of the party purchasing the electric or thermal output. The billing meter must record the hourly electric or thermal output. Any electric or thermal output values that the facility reports must be the same as the values used in billing for the output.

Test specifications

You must decide whether to specify system accuracy requirements, or component accuracy specifications for output monitoring systems, or both. (See below in this section under "*System accuracy determination*", p. 158, for a discussion of what we mean by an output monitoring system.) A system accuracy of 10% of the reference value would be an acceptable accuracy criteria. For a simple output monitoring system, such as a single electric meter on the terminals of a generator, the component and system would be the same and the accuracy of the system would equal the accuracy of the individual component (10% of reference value). However, for a net thermal output system on a non-electric generating unit, the system might consist of two or more steam flow sensors, several temperature sensors, and several pressure sensors. In this case, to achieve a 10% accuracy for the system the individual components should have a more stringent accuracy specification. A simple calculation used to estimate the error associated with multiple components whose individual errors contribute to a system error is the following statistical equation.

$$E_{system} = \sqrt{\sum_{\text{all components}} E_{component}^2}$$

Where

$E_{component}$ = maximum error asociated with each component of a system

E_{system} = maximum theoretical error of the system.

Using this equation we find that two components with error of 10% can lead to a system error of 14.1% in a worst case scenario. Three components could have 17.3% error and so on. A system with 11 components with 3% error each would have a maximum system error of 9.9% using the above equation. It is likely that many steam systems will have at least 11 separate components such as flow meters , temperature sensors. While other choices are possible, a 3% accuracy for each component would be an acceptable accuracy for up to 11 individual components when a system accuracy can not be readily determined.

Any individual component equipment reading output must be capable of measuring to within 3.0 percent of full scale for that piece of equipment. Most of the existing technologies for measuring output are capable of reading to this level of accuracy[21].

System accuracy determination

A monitoring system is a collection of component pieces of equipment which are used together to get a measurement in the units of measure that you require under a regulation. An example of an emissions monitoring system is a system for measuring NOx emission rate in lb/mmBtu, which includes a NOx pollutant concentration monitor, a CO_2 or O_2 diluent monitor, and a data acquisition and handling system. An output monitoring system might consist of the following components:

- All wattmeters and a data logger that a company uses together to calculate the final net or gross electric output data that you will use to calculate allocations.
- All flowmeters for steam or condensate, temperature measurement devices, absolute pressure measurement devices, and differential pressure devices for measuring thermal energy and a data logger. These are all the measurement devices that a company uses together to calculate net or gross thermal output data that you will use to calculate allocations.

If you decide to adopt a system approach to accuracy based on a professional engineering

[21]See Chapter 6 of *Flow Measurement Engineering Handbook*, 3rd Edition, by R.W. Miller (McGraw Hill, 1996). Also, the Massachusetts Department of Environmental Protection has pointed out that existing measurement technologies can meet an accuracy level of 3 percent.

analysis as described above in sections VII.B "How detailed or prescriptive should output monitoring and reporting requirements be in my State rule?" and VII.F., "What should a source be required to report in a monitoring plan?" (pp. 148, 155, respectively), then the description should include a determination of how the system accuracy of 10% is achieved using the individual components in the system.

Test procedures and standards for individual components

The following table lists existing consensus standards that include instructions for calibration or testing of individual equipment to measure steam flow or electricity. We suggest that sources follow these consensus standards, where possible. However, this list is not comprehensive. You should also allow companies the flexibility to petition to use another method of sufficient accuracy, especially if they are methods from standard-setting or professional organizations. Consensus-based industry standards are acceptable from the following organizations:

C American Gas Association (AGA)

C American National Standards Institute (ANSI)

C American Society of Mechanical Engineers (ASME)

C American Society for Testing and Materials (ASTM)

C Institute of Electrical and Electronics Engineers (IEEE) or

C Instrument Society of America (ISA)

Table VII-1: Consensus Standards for Assuring Accuracy of Output Measurement Equipment

Equipment type	Number or name of standard
Electric generation	
Solid-state kilowatt meters	ANSI C12.16 or ASME PTC 19.6
Rotating kilowatt meter	ANSI C12.10, ANSI C12.13, ANSI C12.15, or ASME PTC 19.6
Electromechanical kilowatt meter	ANSI C12.10, ANSI C12.13, ANSI C12.15, or ASME PTC 19.6
Current transformers	IEEE/ANSI 57.13, ANSI C12.11 or ANSI C93.1
Potential transformers	IEEE/ANSI 57.13, ANSI C12.11 or ANSI C93.1

Equipment type	Number or name of standard
Steam	
Pressure taps	AGA Report 3, ASME PTC 19.2, or ASME MFC-3M
Flow venturi	ASME MFC-3M for initial installation
Orifice plate	AGA Rpt. 3, ASME MFC-3M for initial installation
Flow nozzle	ASME MFC-3M for initial installation or ASME PTC-6
Vortex meters	ASME MFC-6M
Turbine meters	ASME MFC-4M; AGA Rpt. 7
Water (condensate)	
Orifice plate	AGA Rpt. 3 or ASME MFC-3M for initial installation
Coriolis meters	ASME MFC-9M or ASME MFC-11M
Pressure	
Pressure transmitters	ASME PTC 19.2
Differential pressure transmitters	ASME PTC 19.2
Temperature	
Temperature transmitters	ASME PTC 19.3
Thermocouples	ASME PTC 19.3
Resistance Temperature Detectors	ASME PTC 19.3

Some of these methods require that the equipment be tested outside of the plant or require that the generating system or unit not operate during the test. Obviously, this could be inconvenient for sources. It is reasonable to consider other alternative procedures for checking the accuracy of equipment that do not require removing equipment from the plant. Any alternative procedures would need to provide you with reasonable confidence that the equipment are reading to within 3.0

percent of the actual output provided by a reference reading.

In addition to the consensus standards for particular technologies, sources can check various kinds of transmitters (e.g., temperature or pressure transmitters) against standards traceable to the National Institute of Standards and Technology (NIST). Section 2.1.6.1 of Appendix D of 40 CFR Part 75 gives procedures for testing transmitters using NIST traceable standards.

Frequency of testing

Certain types of equipment only require an initial certification of calibration and do not require periodic recalibration unless the equipment are physically changed:

- potential transformers
- current transformers
- primary element of an orifice plate (However, the accompanying pressure and temperature transmitters will require periodic retesting.)

Any output measurement equipment used as a billing meter in commercial transactions should not need additional requirements for periodic quality assurance testing. A meter that is sufficiently accurate for commercial transactions should also be sufficiently accurate for providing data to support allocations.

For other types of equipment, we suggest that sources either recalibrate or reverify the meter accuracy at least once every two years (i.e., every eight calendar quarters), unless a consensus standard allows for less frequent calibrations or accuracy tests.

Consequences of failing a QA test

If testing a piece of output measurement equipment shows that the output readings are not accurate to 3.0 percent or less of the full scale, then the source must retest the measurement equipment and meet that requirement. The data should be consider invalid, prospectively, for purposes of determining allocations. Data would remain invalid until the output measurement equipment passed an accuracy test or were replaced with another piece of equipment that passes the accuracy test. The source would need to omit the invalid data and report either zero or an output value that is likely to be lower than a measured value (see section VII.H., “How would a source substitute missing data for output?”, p. 161)

How to correct a test failure

The source must retest the measurement equipment and demonstrate that it meets the accuracy specification you set (e.g., accurate to 3.0 percent or less of full scale for a component or accurate to 10.0 percent or less of the reference readings for an output monitoring system). Alternatively, the source could replace the failing equipment with other equipment that meets this accuracy specification.

Documentation

The source will need to keep the records described above in section VII.F., "What records must affected facilities keep and report to support output-based allocations?" (pp. 153-155).

H. How would a source substitute missing data for output?

If you choose to require missing data substitution procedures, we suggest it be of a very simple and easy to implement nature. The easiest approach is to assume that a source has no output during any missing data period. Other options include using the average of the values before and after the outage as the substitute value or using a minimum value for estimating output.

I. What other monitoring requirements must facilities meet if they are not fossil fuel-fired?

All facilities receiving output-based allocations must measure, quality-assure, record, and report information on output.

Sources that are not fossil fuel-fired

If you include sources emitting NOx that are not fossil fuel-fired, then you will need to add requirements for the owner or operator of those sources to monitor, record and report NOx mass emissions and source operating information (e.g., hours of operation). A source emitting NOx would have to account for its NOx emissions if it is allocated NOx allowances. Companies can monitor NOx, heat input, and output from these sources in the same way as for fossil fuel-fired units. The discussions in the rest of section VII., "Requirements for Sources: How should companies monitor, record, and report output data to support updating output-based allocations?" (pp. 142-162) also apply to non-fossil fuel-fired sources.

Facilities that do not emit NOx

If you choose to allocate NOx allowances to facilities or generating systems that do not emit NOx, such as hydroelectric or nuclear power plants, they will need to measure, quality-assure, record, and report information on electric output. The discussions in the rest of section VII.

"Requirements for Sources: How should companies monitor, record, and report output data to support updating output-based allocations?" (pp. 142-162) also apply to non-emitting generating systems. In addition, these sources would need to keep records of hours of operation during the ozone season. (The discussion in section VII.F. "What records must affected facilities keep and report to support output-based allocations?", pp. 153-155, assumes that fossil fuel-fired units are already monitoring their hours of operation, as required by 40 CFR Part 75.)

VIII. Data Sources: Where do I get the data for an output-based allocation?

A. What are potential sources of output data?

There are three main sources of electric generation data and one source of thermal output data:

Electric generation data

< Collect data directly from facilities in your state.

< Get data from EPA. Quarterly emission reports under the Acid Rain Program contain gross electric generation data for many power plants in the Program, starting in 1995. Some power plants choose to report steam flow to EPA instead of gross electric generation, so this is not a complete source of gross generation data. Furthermore, these data are not quality-assured by the Agency. For more information on data available from the Acid Rain Program, you can check the Acid Rain Program's Web site (http://www.epa.gov/acidrain/edata.html) or call the Acid Rain Hotline at (202) 564-9620.

< Get data from the Energy Information Administration (EIA). EIA collects electric generation for certain utility and non-utility generators. These data were previously collected on EIA forms 759, 767, and 867[22] and will continue to be collected on EIA forms 759, 767, 860B and 900. Form 759 provides net electric generation for utility plants (not units or generators) on a monthly basis for each year during the 1990s[23]. Form 767 provides net electric generation for utility generators connected to boilers[24] for each month during 1997 and earlier. Form 767 information is not available for turbines or combined cycle systems. Form 860B provides annual gross electric generation from non-utility generators[25] during

[22]Electric generation on form 867 for non-utility generators is confidential for specific plants. This form was discontinued in 1997 and was replaced by forms 860B and 900.

[23]If each of the utility's plants has a total nameplate capacity of less than 50 MW, then the utility only needs to report annually instead of monthly.

[24] Utilities will report electric generation for plants with a total nameplate capacity of 100 MW or more.

[25] These include qualifying facilities under the Public Utilities Regulatory Policies Act and exempt wholesale generators under the Energy Policy Act. Plants with a nameplate capacity

1998 and later. Form 900 provides monthly net (or gross) electric generation from non-utility generators[26] during 1999 and later. For more information about the appropriate contact people at EIA for these forms, you can check EIA's Web site (http://www.eia.doe.gov/contacts/main.html) or you can contact the National Energy Information Center at infoctr@eia.doe.gov, Telephone: (202) 586-8800.

Thermal output data

< Collect data directly from facilities in your state.

B. What should I consider when choosing a source of output data?

Here are some factors you will want to consider when deciding from where to get your output data.

Data for electric generating units or for non-electric generating units

If you intend to allocate allowances on the basis of output to non-electric generating units or cogeneration units, it will be necessary for you to collect thermal output data directly from sources in the short term.

Data for conventional power plants (not cogeneration facilities)

If your state has only electric generating units, and none of them are cogenerators, you will only need electric generation data. In this instance, it may be possible to use any of the three data sources. Note that EIA's electric generation for non-utility generators is treated as confidential and is not available for years before 1998.

Size of affected sources in your State

EPA's data are not and will not be available for electric generating units serving generators of 25 MW or less. In addition, EPA's gross generation data are not currently available for simple combustion turbines that were built before November 15, 1990. Some data from EIA forms are not available for plants with a total nameplate capacity less than 100 or 50 MW, or at least not available on a monthly basis.

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of 1 MW or greater must file this form.

[26] These include qualifying facilities under the Public Utilities Regulatory Policies Act and exempt wholesale generators under the Energy Policy Act. Non-utility electricity generating plants with a nameplate capacity of 50 MW or greater must file this form.

Use of gross or net generation data

EPA's current generation data are gross electric output data for many, but not all, utility units in the Acid Rain Program. EIA's generation data are net generation values for utility generators and are a mixture of net and gross generation values for non-utility generators. If you collect your own data, you can request either gross or net generation data.

Level of data for allocations–plant vs. generator vs. unit

EPA generation data are at the unit level. EIA form 767 provides generation data for each generator. EIA forms 759, 860B, and 900 provide generation data only for entire plants. Plant-level data would need to be apportioned to individual units at a plant to create allocations for each unit.

Time interval of data

Most of EIA's generation data are monthly data, which you can sum for May through September to obtain the total output for the ozone season.

If you choose to use existing gross electric output data[27] for the Acid Rain Program, you will have access to hourly data. However, you will need to sum the hourly values to calculate the ozone season total electric output. We advise states to take this approach with caution because extracting these data from the electronic data reporting (EDR) format could be costly and time consuming.

The steam load data that some sources report to EPA for the Acid Rain Program are hourly data. However, because this information is steam flow in lb/hr without temperature, pressure, or enthalpy data, it does not give you the information you need to determine thermal output.

Degree of quality assurance and consistency

Sources are not currently required to perform quality assurance testing on equipment used to measure output. This is true, whether the data are reported to EPA, to EIA, or to you. Some sources follow voluntary standards from the American National Standards Institute (ANSI) or the Institute of Electrical and Electronics Engineers (IEEE). Therefore, some of the data are highly accurate, but this is not consistently true.

You can request data in a standard format. EIA has standard forms that sources are required to submit. EPA has a standard electric format for reporting gross MW data. However, sources have

[27] Sources report these data in record type 300 of EPA's electronic data reporting format.

the option of reporting either gross unit load data (MWe) or gross steam flow rate data to EPA.

Although there is a standard format for reporting the data, the data themselves are not necessarily being reported consistently. This could be improved by giving consistent interpretations of reporting instructions and by providing more consistent quality assurance of the data.

Availability of data in electronic form

Data from EIA form 759 are available in electronic files on EIA's Web site. Data from the Acid Rain Program are readily available on files on the Acid Rain Program Web site. You can also request other data files directly from EIA.

Time when data are available for the public

It generally takes EPA six months to review data sufficiently before making them publicly available. EIA form 759 is usually ready within six months of the end of the year. Data from other EIA forms may take longer to become publicly available. The quickest way to obtain data may be to ask sources directly.

Use of your staff resources

A State collection of data on paper can be time and resource intensive. If you have relatively few sources in your state and if almost all of your sources are electric generating units, you may be able to take advantage of electronically available data from the Federal government.

IX. Rule Changes: What provisions of my State rule may need to be changed to account for output-based NOx allowance allocations?

You may need to change the following provisions or sections of your rule to account for output-based NOx allowance allocations:

- Definitions
- Measurements, abbreviations and acronyms
- Applicability
- NOx allowance allocations
- Monitoring

In Appendix A to this guidance document, you will find example language that you may use in your State rule. The example language is based upon the language in the model rule for the NOx Budget Trading Program under the NOx SIP call at 40 CFR part 96.

You may need to make the following sorts of changes for each of these sections or provisions:

Definitions (§96.2) –Add definitions for output, electric output, thermal output, net output, and gross output, as appropriate to your regulation. This will depend on the location you choose for monitoring output and the sources you choose to give allocations to using output (see section III "For which kinds of facilities does this guidance help me develop output-based allocations?", pp. 44-45 above and section V, "Where should sources determine output to be used for allocations?", pp. 49-54 above). Your definitions will determine the monitoring approach to be used, which in turn determines the formulas to be used for allocation. In addition, if you decide to issue allowances to all generation sources, you will need language to describe generating systems that are non-fossil fuel-fired or that are non-emitting generating systems. If you include sources that are not fossil fuel-fired, you may want to revise the definition of a NOx Budget unit to include boilers, turbines, or combined cycle systems that combust any fuel. See the example definitions in Appendix A (pp. 171-172).

Measurements, abbreviations and acronyms (§96.3)–Add abbreviations for the units of measure for output: MWh (megawatt-hour) and $mmBtu_{out}$ or mmBtu output (measured million British thermal units of thermal output)

Applicability (§96.4)–You will need to revise this section or provision if you decide to issue allowances to all generation sources, rather than just fossil-fuel sources. NOx-emitting electric generating systems, including fossil fuel-fired or non-fossil fuel-fired units, will need to meet the requirements for NOx Budget units. These include the requirements to hold allowances covering emissions and to monitor and report NOx emissions and output data. Any NOx-emitting sources that are not fossil fuel-fired will need to meet the same requirements as fossil fuel-fired units. Non-emitting generating systems will need to meet the requirements for owners of a general allowance account and requirements for monitoring and reporting output data. If you handle applicability through your definitions, review your definitions to see if they still are appropriate.

<u>NOx allowance allocations (§96.42)</u>–You will be making most of your rule revisions in this section. You may need different calculation formulas and procedures for adjusting the amounts of the allowance allocations so that the total amount equals the appropriate portion of your trading program budget. Also, you will need to address whether to update allocations for your facilities and, if so, how often to update allocations for your facilities. Formulas for calculating thermal output must be consistent with the monitoring approach you define.

<u>Monitoring (§§96.70 through 96.76)</u>–See section VII, "Requirements for Sources: How should sources monitor, record, and report output data to support updating output-based allocations?" (pp. 142-162). You will need to define the monitor installation, quality assurance, recordkeeping, and reporting requirements for all sources receiving output-based allocations. Depending on whether you plan to allocate based on output to electric generating units only or to both electric generating units or non-electric generating units, this section of your rule will need to specify which kinds of units must measure, record, and report output data.

If you choose to include all generation sources instead of fossil-fuel fired sources only, then you will need to add requirements for the owner or operator of a non-fossil fuel-fired source to monitor, record and report emissions and source operating information. See section VII.I. of this document, "What other monitoring requirements must facilities meet if they are not fossil fuel-fired?" (pp. 161-162).

X. How do I learn more about this guidance?

A. Who do I contact if I have questions about this guidance?

If you have questions about this guidance, contact Margaret Sheppard at EPA's Clean Air Markets Division[28] (Telephone: 202-564-9163; email: sheppard.margaret@epa.gov). If you have specific questions or suggestions related to output monitoring and reporting, contact either Margaret Sheppard or George Croll (Telephone: 202-564-0162; email: croll.george@epa.gov) at EPA's Clean Air Markets Division.

B. How do I find out more about the NOx SIP Call and the NOx Budget Trading Program?

EPA's information about the NOx SIP call is available on the Regional Transport of Ozone Web site (http://www.epa.gov/ttn/rto/sip/index.html). This site includes a number of resources, including Federal Register notices, fact sheets, supporting technical work, emission inventories, and responses to frequently-asked questions. The Federal Register notice with the final NOx SIP call is entitled "FR version of the 110 NOx SIP call -- Parts 1-4 (zipped)" and dated October 30, 1998.

If you have specific questions about the NOx SIP call, you may contact Kimber Scavo of EPA's Office of Air Quality, Planning and Standards (Telephone: 919-541-3354; email: scavo.kimber@epa.gov). If you have specific questions concerning the NOx Budget Trading Program, contact Sarah Dunham of the Clean Air Markets Division (Telephone: 202-564-9087; email: dunham.sarah@epa.gov).

C. How did EPA create this guidance?

In the final NOx SIP call, we committed to work together with stakeholders to design an output allocation system that could be used by States as part of their trading program rules in their SIPs. We said that we would develop a proposed system for output-based allocations in 1999 and finalize an output-based option in 2000. Today's guidance develops the final system for output-based allocations that we committed to in the NOx SIP call.

EPA formed the Updating Output Emission Limitation Workgroup as a stakeholder workgroup to advise us in addressing issues to be covered in guidance to States. The Updating Output Emission Limitation Workgroup is a workgroup of the Clean Air, Energy and Climate

[28] Formerly the Acid Rain Division.

Change Subcommittee of the Clean Air Act Advisory Committee. Workgroup members include representatives of the electric power industry, district energy groups, industrial boiler owners, the natural gas supply industry, environmental groups, State environmental agencies, labor unions, and other organizations. From December 1998 through December 1999, we held a series of meetings and conference calls.

You can find information on the work of the Updating Output Emission Limitation Workgroup on the workgroup's Web site (http://www.epa.gov/acidrain/noxsip/workgrp.htm). On the site, you will find a list of workgroup members and their affiliations, lists of questions that we posed to the workgroup, responses by workgroup members, issue papers, the first draft of this guidance document, and meeting minutes. Some of these documents are referred to in the guidance.

Appendix A: Sample rule language to account for output-based allocations

Note that throughout these examples, some phrases are in italics. These indicate possible decisions that you will need to make. For example, the definitions of "non-emitting generating system" and "unit" below will apply only if you intend to allocate to all sources of electric generation instead of to fossil fuel-fired units.

Definitions

"Electric output" means the electric generation (in MWh/time) from an electric generating device. With respect to a unit, "electric output" means the electric generation (in MWh/time) from an electric generating device served by the unit and that is attributed to the unit.

"Gross output" means the total output of energy from a process before making any deductions for energy output used in any way related to the production of energy through that process.

"Net output" means the final output of energy from a process after deducting any energy output consumed in any way related to generating energy through that process. Examples of output to be deducted include thermal output lost through radiation to the outside, thermal output used in thermal recovery, or thermal or electric output used within the plant to operate the unit, generator, fuel handling system, pumps, fans, or pollution control equipment[29]. Output used to produce a useful material product besides the thermal output or electric output, such as thermal energy used to dry paper, does not need to be deducted.

{include this definition, if you intend to allocate NOx allowances to all electricity generating systems}"Non-emitting generating system" means the portion of a facility for generating electricity that uses an energy source not involving combustion of fuel or NOx emissions, such as hydroelectric, nuclear, geothermal, or wind power, and that uses an electric generator with a nameplate capacity greater than 25 MWe.

"NOx Budget unit" means a unit that is subject to the NOx Budget Trading Program emissions limitation under § 96.4 or § 96.80.

[29] If you intend to include the power used to operate pollution control equipment as part of the electric output used to calculate allocations, remove "pollution control equipment" from this part of the definition.

"Thermal output" means the thermal energy (in $mmBtu_{out}$/time) that is produced through a process and is used for industrial, commercial, heating, or cooling purposes after the subtraction of heat for boiler feed, feedwater preheating, or combustion air preheating.[30]

"Unit" means a stationary boiler, combustion turbine, or combined cycle system that is fossil fuel-fired.[31]

Measurements, abbreviations, and acronyms

MWh-megawatt-hours of electric output

$mmBtu_{out}$–measured million British thermal units of thermal output

[30] Note that this definition only applies when you measure thermal output using the boiler efficiency approach, as described in section VI. of this document (pp. 68-69, 84-91, and 124-137). If you choose to use the simplified approach for monitoring thermal output, then the definition of thermal output should read as follows:

> "Thermal output" means the thermal energy (in $mmBtu_{out}$/time) that is produced through a process and is used for industrial, commercial, heating, or cooling purposes after the subtraction of heat for boiler feed or combustion air preheating.

[31] If you intend to allocate NOx allowances to all electricity generating systems, revise the definition of unit as follows:

> "Unit" means a stationary boiler, combustion turbine, or combined cycle system that combusts fuel.

Subpart E - NOx Allowance Allocations

Note that throughout these examples, some phrases are in italics. These indicate possible decisions that you will need to make. For example, if you want to use net generation, substitute in the phrase "net" in each place where the example language states "*{specify net or gross}*."

The example language in Cases 1 and 3 allows for the situation where a State has already prepared initial allocations for 2003 through 2005 based on heat input and intends to update allocations based on output starting with the year 2006. Cases 2 and 4 consider the situation where a State has prepared initial allocations for 2003 through 2005 based on output and intends to update allocations based on output starting with the year 2006. In all cases, allocations are adjusted to fit sector budgets, rather than the entire trading program budget. Also, there is a 5% set-aside for new units in all cases.

The dates in all cases are based upon the timing in part 96, the model trading rule for the NOx SIP call. The timing in your rule will depend on when you adopt a final rule as part of your SIP and on the deadline for sources to comply with emission reductions

Case 1

(1) You initially allocate to both EGUs and non-EGUs for 2003 through 2005 based on heat input

(2) You update allocations to EGUs based on output and to non-EGUs based on heat input beginning in 2006

§ 96.42 NOx allowance allocations.

(a) *Basis for allocation.* The permitting authority will calculate NOx allowance allocations for each NOx Budget unit under § 96.4 [*or non-emitting generating system*] as follows:

(1) For a NOx allowance allocation for 2003 through 2005 under §96.41(a):

(i) The permitting authority will use the average of the two highest amounts of the unit's heat input (in mmBtu) for the control periods in 1995, 1996, and 1997 if the unit is under §96.4(a)(1), or the unit's heat input for the control period in 1995 if the unit is under §96.4(a)(2); or

(ii) For a unit under §96.4(a)(1) that commences operation on or after May 1, 1997, or for a unit under §96.4(a)(2) that commences operation on or after May 1, 1995, the permitting authority will use the unit's heat input in accordance with paragraph (d) of this section.

(2) For a NOx allowance allocation for any year after 2005 under §96.41(b):

(i) The permitting authority will use the *{specify net or gross}* electric and thermal output for the unit under §96.4(a)(1) *[or the non-emitting generating system]*, and heat input for the unit under §96.4(a)(2) for the control period in the year that is four years before the year for which the NOx allocation is being calculated; or

(ii) For a unit *[or non-emitting generating system]* that commences operation on or after May 1 of the year that is four years before the year for which the permitting authority allocates, the permitting authority will determine allocations in accordance with paragraph (d) of this section.

(3) The permitting authority will determine the unit's heat input:

(i) In accordance with 40 CFR part 75; or

(ii) Based on the best available data reported to the permitting authority for the unit, if the unit was not otherwise subject to the requirements of 40 CFR part 75 for the control period.

(4) The permitting authority will determine the *{specify gross or net}* thermal and electric output for the unit [*or non-emitting generating system]* using {*insert source of data–e.g., net electric generation data from the Energy Information Administration, gross electric generation data in accordance with subpart H of 40 CFR part 75, or the best available data reported to the permitting authority for the unit or non-emitting generating system.}*

(b) *Allocation to units under §96.4(a)(1)[and non-emitting generating systems]*. For each control period in 2003 through 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(1) in [the State] *{substitute name of your State}* that commenced operation before May 1, 1997 in accordance with paragraphs (b)(1) through (b)(3) of this section. For each control period after 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(1) *[or non-emitting generating systems]* in [the State] *{substitute name of your State}* that commenced operation before May 1 of the period used to calculate heat input or electric and thermal output under paragraph (a) of this section, in accordance with paragraphs (b)(4) through (b)(6) of this section.

(1) For 2003 through 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(1) in [the State] *{substitute name of your State}* that commenced operation before May 1, 1997.

(2) For 2003 through 2005, the permitting authority will allocate NOx allowances to each NOx Budget unit under §96.4(a)(1) in an amount equaling 0.15 lb/mmBtu multiplied by the unit's heat input under paragraph (a) of this section, divided by 2,000 lb/ton. Each allocation will be rounded to the nearest whole number of NOx allowances, as appropriate.

(3) The permitting authority will adjust the initial allocations under paragraph (b)(2) of this section so that the total number of NOx allowances allocated for 2003, 2004, or 2005 equals 95 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's allocation for 2003, 2004, or 2005 by 95 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1), dividing by the total number of NOx allowances allocated for the year under paragraph (b)(2) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(4) For each control period after 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(1) [*and to all non-emitting generating systems]* in [the State] *{substitute name of your State}* that commenced operation before May 1 of the period used to calculate *{specify net or gross}* electric and thermal output under paragraph (a)(2) of this section.

(5) For each control period after 2005, the permitting authority will allocate NOx allowances to each unit under §96.4(a)(1) *[and to each non-emitting generating system]* in an amount equaling: 1.5 lb/MWh multiplied by the *{specify net or gross}* electric output under paragraph (a) of this section and divided by 2,000 lb/ton, plus 0.24 lb/mmBtu$_{out}$[32] multiplied by the *{specify net or gross}*

[32]Use the value of 0.24 lb/mmBtu output if you assume a typical boiler efficiency of 70% and if you require sources to use the boiler efficiency approach for measuring thermal output, as described in section VI. of this document (pp. 68-69, 84-91, and 124-137). If you decide to use the simplified approach for monitoring output and a typical boiler efficiency of 70%, then this number should be 0.22 lb/mmBtu. If you want to assume a different typical boiler efficiency, see

thermal output under paragraph (a) of this section and divided by 2,000 lb/ton. Each allocation will be rounded to the nearest whole number of NOx allowances, as appropriate.

(6) The permitting authority will adjust the initial allocations under paragraph (b)(5) of this section so that the total number of NOx allowances allocated for each control period after 2005 equals 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's allocation for a control period after 2005 by 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1) divided by the total number of NOx allowances allocated under paragraph (b)(5) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(c) *Allocation to units under §96.4(a)(2).* For each control period under § 96.41, the permitting authority will allocate NOx allowances to all units under §96.4(a)(2) in [the State] *{insert name of State}* that commenced operation before May 1 of the period used to calculate heat input under paragraph (a) of this section. The permitting authority will allocate NOx allowances in accordance with the following procedures:

(1) The permitting authority will allocate NOx allowances to each NOx Budget unit under §96.4(a)(2) in an amount equaling 0.17 lb/mmBtu multiplied by the heat input under paragraph (a) of this section, divided by 2,000 lb/ton. Each allocation will be rounded to the nearest whole number of NOx allowances, as appropriate

(2) The permitting authority will adjust the unadjusted allocations under paragraph (c)(1) of this section so that the total number of NOx allowances allocated equals 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(2), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's for a control period by 95 percent in 2003, 2004, or 2005, or by 98 percent thereafter, of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(2), dividing by the total number of NOx allowances allocated under paragraph (c)(1) of this section, and rounding to the nearest whole

section II.A. to calculate your own allocation factor (pp. 23-31).

number of NOx allowances, as appropriate.

(d) For each control period under § 96.41, the permitting authority will allocate NOx allowances to NOx Budget units under § 96.4 *[or non-emitting generating systems]* in [the State] *{insert name of your State}* that commenced operation, or are projected to commence operation, on or after May 1 of the period used to calculate heat input or electric and thermal output under paragraph (a) of this section, in accordance with the following procedures:

(1) The permitting authority will establish one allocation set-aside for each control period. Each allocation set-aside will be allocated NOx allowances equal to 5 percent in 2003, 2004, and 2005, or 2 percent thereafter, of the tons of NOx emissions in the State trading program budget, rounded to the nearest whole number of NOx allowances, as appropriate.

(2) The NOx authorized account representative of a unit under paragraph (d) of this section may submit to the permitting authority a request, in writing or in a format specified by the permitting authority, to be allocated NOx allowances for no more than five consecutive control periods under § 96.41, starting with the control period during which the unit commenced, or is projected to commence, operation and ending with the control period preceding the control period for which it will receive an allocation under paragraph (b) or (c) of this section. *{If including non-emitting generating systems, include the following sentence: The NOx authorized account representative of a non-emitting generating system under paragraph (d) of this section may submit to the permitting authority a request, in writing or in a format specified by the permitting authority, to be allocated NOx allowances for no more than five consecutive control periods under § 96.41, starting with the later of the control period in 2006 or the control period during which the non-emitting generating system commenced, or is projected to commence, operation and ending with the control period preceding the control period for which it will receive an allocation under paragraph (b) or (c) of this section.* The NOx allowance allocation request must be submitted prior to May 1 of the first control period for which the NOx allowance allocation is requested and after the date on which the permitting authority issues a permit to construct the unit *[or non-emitting generating system]*.

(3) In a NOx allowance allocation request under paragraph (d)(2) of this section, the NOx authorized account representative for a unit under §96.4(a)(1) *[or a non-emitting generating system]* may request NOx allowances for a control period in the following amount:

(i) For a control period in 2003, 2004, or 2005, the requested number of NOx allowances must not exceed 0.15 lb/mmBtu, multiplied by the unit's maximum design heat input (in mmBtu/hr), multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate, and divided by 2,000 lb/ton.

(ii) For a control period in 2006 or thereafter, the requested number of NOx allowances must not exceed 1.5 lb/MWh multiplied by the nameplate capacity (in MW) of the unit *[or non-emitting generating system]*, multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate, and divided by 2,000 lb/ton.

(4) In a NOx allowance allocation request under paragraph (d)(2) of this section, the NOx authorized account representative for a unit under §96.4(a)(2) may request NOx allowances for a control period. The requested number of NOx allowances must not exceed 0.17 lb/mmBtu multiplied by the unit's maximum design heat input (in mmBtu/hr), multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate, and divided by 2,000 lb/ton.

(5) The permitting authority will review, and allocate NOx allowances pursuant to, each NOx allowance allocation request under paragraph (d)(2) of this section in the order that the request is received by the permitting authority.

(i) Upon receipt of the NOx allowance allocation request, the permitting authority will make any necessary adjustments to the request to ensure that, for a unit under §96.4(a)(1) *[or non-emitting generating system]*, the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (3) of this section and, for a unit under §96.4(a)(2), the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (4) of this section.

(ii) If the allocation set-aside for the control period for which NOx allowances are requested has an amount of NOx allowances not less than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will allocate the amount of the NOx allowances requested (as adjusted under paragraph (d)(5)(i) of this section) to the unit *[or non-emitting generating system]*.

(iii) If the allocation set-aside for the control period for which NOx allowances are requested has a smaller amount of NOx allowances than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will deny in part the request and allocate only the remaining number of NOx allowances in the allocation set-aside to the unit *[or non-emitting generating system]*.

(iv) Once an allocation set-aside for a control period has been depleted of all NOx allowances, the permitting authority will deny, and will not allocate any NOx allowances pursuant to, any NOx allowance allocation request under which NOx allowances have not already been allocated for the control period.

(6) Within 60 days of receipt of a NOx allowance allocation request, the permitting authority will take appropriate action under paragraph (d)(5) of this section and notify the NOx authorized account representative that submitted the request and the Administrator of the number of NOx allowances (if any) allocated for the control period to the unit *[or non-emitting generating system]*.

(e) For a unit *[or non-emitting generating system]* allocated NOx allowances under paragraph (d) of this section for a control period, the Administrator will deduct NOx allowances under § 96.54(b) or (e) to account for the actual utilization or output of the unit *[or non-emitting generating system]* during the control period. The Administrator will calculate the number of NOx allowances to be deducted to account for the unit's actual utilization or output using the following formulas and rounding to the nearest whole number of NOx allowances as appropriate, provided that the number of NOx allowances to be deducted shall be zero if the number calculated is less than zero:

NOx allowances deducted for actual utilization for a unit under §96.4(a)(1) for a control period in 2003, 2004, or 2005 = (NOx allowances allocated for control period) - (Actual control period heat input x 0.15 lb/mmBtu ÷2,000 lb/ton);

NOx allowances deducted for actual output for a unit under §96.4(a)(1) *[or a non-emitting generating system]* for a control period in 2006 or thereafter = (Unit's NOx allowances allocated for control period) - (Unit's actual control period *{specify net or gross}* electric output x 1.5 lb/MWh ÷2,000 lb/ton and actual control period *{specify net or gross}* thermal output x0.24 lb/$mmBtu_{out}$[33]

[33] Same as footnote 32.

÷2,000 lb/ton); and

NOx allowances deducted for actual utilization for a unit under §96.4(a)(2)= (NOx allowances allocated for control period) - (Actual control period heat input x 0.17 lb/mmBtu ÷2,000 lb/ton)

where:

"NOx allowances allocated for control period" is the number of NOx allowances allocated to the unit *[or the non-emitting generating system]* for the control period; and

"Actual control period heat input" is the heat input (in mmBtu) of the unit during the control period; and

"Actual control period *{specify net or gross}* electric output" is the *{specify net or gross}* electric output in MWh of the unit *[or non-emitting generating system]* during the control period; and

"Actual control period *{specify net or gross}* thermal output" is the *{specify net or gross}* thermal output in $mmBtu_{out}$ of the unit during the control period.

(f) After making the deductions for compliance under § 96.54(b) or (e) for a control period, the Administrator will notify the permitting authority whether any NOx allowances remain in the allocation set-aside for the control period. The permitting authority will allocate any such NOx allowances to the units under §96.4 *[and the non-emitting generating systems]* in [the State] *{insert name of your State}* using the following formula and rounding to the nearest whole number of NOx allowances as appropriate:

Unit's *[or non-emitting generating system's]* share of NOx allowances remaining in allocation set-aside = Total NOx allowances remaining in allocation set-aside x (NOx allowance allocation ÷ State trading program budget excluding allocation set-aside)

where:

"Total NOx allowances remaining in allocation set-aside" is the total number of NOx allowances remaining in the allocation set-aside for the control period;

" NOx allowance allocation" is the number of NOx allowances allocated under paragraph (b) or (c) of this section to the unit *[or non-emitting generating system]* for the control period to which the allocation set-aside applies; and

"State trading program budget excluding allocation set-aside" is the State trading program budget for the control period to which the allocation set-aside applies multiplied by 95 percent if the control period is in 2003, 2004, or 2005 or 98 percent if the control period is in any year thereafter, rounded to the nearest whole number of NOx allowances as appropriate.

Case 2

(1) You initially allocate to both EGUs and non-EGUs for 2003 through 2005 based on heat input

(2) You update with allocations to both EGUs and non-EGUs based on output beginning in 2006

§ 96.42 NOx allowance allocations.

(a) *Basis for allocation.* The permitting authority will calculate NOx allowance allocations for each NOx Budget unit under § 96.4 [*or non-emitting generating system*] as follows:

(1) For a NOx allowance allocation for 2003 through 2005 under §96.41(a):

(i) The permitting authority will use the average of the two highest amounts of the unit's heat input (in mmBtu) for the control periods in 1995, 1996, and 1997 if the unit is under §96.4(a)(1), or the unit's heat input for the control period in 1995 if the unit is under §96.4(a)(2); or

(ii) For a unit under §96.4(a)(1) that commences operation on or after May 1, 1997, or for a unit under §96.4(a)(2) that commences operation on or after May 1, 1995, the permitting authority will use the unit's heat input in accordance with paragraph (d) of this section.

(2) For a NOx allowance allocation for any year after 2005 under §96.41(b):

(i) The permitting authority will use the *{specify net or gross}* electric and thermal output for the unit *[or the non-emitting generating system]* for the control period in the year that is four years before the year for which the NOx allocation is being calculated; or

(ii) For a unit *[or non-emitting generating system]* that commences operation on or after May 1 of the year that is four years before the year for which the permitting authority allocates, the permitting authority will determine allocations in accordance with paragraph (d) of this section.

(3) The permitting authority will determine the unit's heat input:

(i) In accordance with 40 CFR part 75; or

(ii) Based on the best available data reported to the permitting authority for the unit, if the unit was not otherwise subject to the requirements of 40 CFR part 75 for the control period.

(4) The permitting authority will determine the *{specify gross or net}* thermal and electric output for the unit [*or the non-emitting generating system]* using {*insert source of data–e.g., net*

electric generation data from the Energy Information Administration, gross electric generation data in accordance with subpart H of 40 CFR part 75, or the best available data reported to the permitting authority for the unit [or the non-emitting generating system].}

(b) *Allocation to units under §96.4(a)(1)[and non-emitting generating systems]*. For each control period in 2003 through 2005, the permitting authority will allocate NOx allowances to all units under §96.4(a)(1) in [the State] *{substitute name of your State}* that commenced operation before May 1, 1997 in accordance with paragraphs (b)(1) through (b)(3) of this section. For each control period after 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(1) *[or non-emitting generating systems]* in [the State] *{substitute name of your State}* that commenced operation before May 1 of the period used to calculate heat input or electric and thermal output under paragraph (a) of this section, in accordance with paragraphs (b)(4) through (b)(6) of this section.

(1) For 2003 through 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(1) in [the State] *{substitute name of your State}* that commenced operation before May 1, 1997.

(2) For 2003 through 2005, the permitting authority will allocate NOx allowances to each NOx Budget unit under §96.4(a)(1) in an amount equaling 0.15 lb/mmBtu multiplied by the unit's heat input under paragraph (a) of this section, divided by 2,000 lb/ton. Each allocation will be rounded to the nearest whole number of NOx allowances, as appropriate.

(3) The permitting authority will adjust the initial allocations under paragraph (b)(2) of this section so that the total number of NOx allowances allocated for 2003, 2004, or 2005 equals 95 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's allocation for 2003, 2004, or 2005 by 95 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1), dividing by the total number of NOx allowances allocated for the year under paragraph (b)(2) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(4) For each control period after 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(1) [*and to all non-emitting generating systems]* in [the State]

{substitute name of your State} that commenced operation before May 1 of the period used to calculate *{specify net or gross}* electric and thermal output under paragraph (a)(2) of this section.

(5) For each control period after 2005, the permitting authority will allocate NOx allowances to each unit under §96.4(a)(1) *[and to each non-emitting generating system]* in an amount equaling: 1.5 lb/MWh multiplied by the *{specify net or gross}* electric output under paragraph (a) of this section and divided by 2,000 lb/ton, plus 0.24 lb/mmBtu$_{out}$[34] multiplied by the *{specify net or gross}* thermal output under paragraph (a) of this section and divided by 2,000 lb/ton. Each allocation will be rounded to the nearest whole number of NOx allowances, as appropriate.

(6) The permitting authority will adjust the initial allocations under paragraph (b)(5) of this section so that the total number of NOx allowances allocated for each control period after 2005 equals 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's allocation for a control period after 2005 by 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1) divided by the total number of NOx allowances allocated under paragraph (b)(5) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(c) *Allocation to units under §96.4(a)(2).* For each control period in 2003 through 2005, the permitting authority will allocate NOx allowances to all units under §96.4(a)(2) in [the State] *{substitute name of your State}* that commenced operation on or after May 1, 1995, in accordance with paragraphs (c)(1) through (c)(3) of this section. For each control period after 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(2) in [the State] *{substitute name of your State}* that commenced operation before May 1 of the period used to calculate heat input or electric and thermal output under paragraph (a) of this section, in accordance with paragraphs (c)(4) through (c)(6) of this section.

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[34]Use the value of 0.24 lb/mmBtu output if you assume a typical boiler efficiency of 70% and if you require sources to use the boiler efficiency approach for measuring thermal output, as described in section VI. of this document (pp. 68-69, 84-91, and 124-137). If you decide to use the simplified approach for monitoring output and a typical boiler efficiency of 70%, then this number should be 0.22 lb/mmBtu. If you want to assume a different typical boiler efficiency, see section II.A. to calculate your own allocation factor (pp. 23-31).

(1) For 2003 through 2005, the Department will allocate NOx allowances to all NOx Budget units under §96.4(a)(2) in [the State] *{substitute name of your State}* that commenced operation before May 1, 1997.

(2) For 2003 through 2005, the permitting authority will allocate NOx allowances to each NOx Budget unit under §96.4(a)(2) in an amount equaling 0.17 lb/mmBtu multiplied by the heat input under paragraph (a) of this section, divided by 2,000 lb/ton. Each allocation will be rounded to the nearest whole number of NOx allowances, as appropriate

(3) For 2003 through 2005, the permitting authority will adjust the initial allocations under paragraph (c)(2) of this section so that the total number of NOx allowances allocated equals 95 percent in 2003, 2004, or 2005, or 98 percent thereafter, of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(2), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's allocation in 2003, 2004, or 2005 by 95 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(2), dividing by the total number of NOx allowances allocated under paragraph (c)(2) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(4) For each control period after the year 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(2) in [the State] *{substitute name of your State}* that commenced operation before May 1 of the period used to calculate *{specify net or gross}* electric and thermal output under paragraph (a)(2) of this section.

(5) For each control period after 2005, the permitting authority will allocate NOx allowances to each unit under §96.4(a)(2) in an amount equaling: 0.24 $lb/mmBtu_{out}$[35] multiplied by the *{specify net or gross}* thermal output under paragraph (a) of this section and divided by 2,000 lb/ton, plus 1.5 lb/MWh multiplied by the *{specify net or gross}* electric output under paragraph (a) of this section and divided by 2,000 lb/ton. Each allocation will be rounded to the nearest whole number of NOx allowances, as appropriate.

(6) The permitting authority will adjust the initial allocations under paragraph (c)(5) of this

[35] Same as footnote 34.

section so that the total number of NOx allowances allocated for each control period after 2005 equals 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(2), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's allocation for a control period after 2005 by 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(2) and dividing by the total number of NOx allowances allocated under paragraph (c)(5) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(d) For each control period under § 96.41, the permitting authority will allocate NOx allowances to NOx Budget units under § 96.4 *[or non-emitting generating systems]* in [the State] *{insert name of your State}* that commenced operation, or are projected to commence operation, on or after May 1 of the period used to calculate heat input or electric and thermal output under paragraph (a) of this section, in accordance with the following procedures:

(1) The permitting authority will establish one allocation set-aside for each control period. Each allocation set-aside will be allocated NOx allowances equal to 5 percent in 2003, 2004, and 2005, or 2 percent thereafter, of the tons of NOx emissions in the State trading program budget, rounded to the nearest whole number of NOx allowances, as appropriate.

(2) The NOx authorized account representative of a unit under paragraph (d) of this section may submit to the permitting authority a request, in writing or in a format specified by the permitting authority, to be allocated NOx allowances for no more than five consecutive control periods under § 96.41, starting with the control period during which the unit commenced, or is projected to commence, operation and ending with the control period preceding the control period for which it will receive an allocation under paragraph (b) or (c) of this section. *{If including non-emitting generating systems, include the following sentence: The NOx authorized account representative of a non-emitting generating system under paragraph (d) of this section may submit to the permitting authority a request, in writing or in a format specified by the permitting authority, to be allocated NOx allowances for no more than five consecutive control periods under § 96.41, starting with the later of the control period in 2006 or the control period during which the non-emitting generating system commenced, or is projected to commence, operation and ending with the control period preceding the control period for which it will receive an allocation under paragraph (b) or (c) of*

this section.} The NOx allowance allocation request must be submitted prior to May 1 of the first control period for which the NOx allowance allocation is requested and after the date on which the permitting authority issues a permit to construct the unit *[or non-emitting generating system]*.

(3) In a NOx allowance allocation request under paragraph (d)(2) of this section, the NOx authorized account representative for a unit under §96.4(a)(1) *[or a non-emitting generating system]* may request NOx allowances for a control period in the following amount:

(i) For a control period in 2003, 2004, or 2005, the requested number of NOx allowances must not exceed 0.15 lb/mmBtu, multiplied by the unit's maximum design heat input (in mmBtu/hr), multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate, and divided by 2,000 lb/ton.

(ii) For a control period in 2006 or thereafter, the requested number of NOx allowances must not exceed 1.5 lb/MWh multiplied by the nameplate capacity (in MW) of the unit *[or non-emitting generating system]*, multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate, and divided by 2,000 lb/ton.

(4) In a NOx allowance allocation request under paragraph (d)(2) of this section, the NOx authorized account representative for a unit under §96.4(a)(2) may request NOx allowances for a control period in the following amount:

(i) For a control period in 2003, 2004, or 2005, the requested number of NOx allowances must not exceed 0.17 lb/mmBtu multiplied by the unit's maximum design heat input (in mmBtu/hr), multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate, and divided by 2,000 lb/ton.

(ii) For a control period in 2006 or thereafter, the requested number of NOx allowances must not exceed 0.24 $lb/mmBtu_{out}$,[36] multiplied by the maximum design heat input of the unit (in mmBtu/hr), divided by an efficiency factor of 0.70,[37] multiplied by the number of hours remaining

[36] Same as footnote 34.

[37] This efficiency factor of 0.70 is appropriate for use with the boiler efficiency approach for measuring output, as described in section VI. of this document (pp. 68-69, 84-91, and 124-137). If you decide to use the simplified approach for monitoring thermal output and a typical

in the control period starting with the first day in the control period on which the unit operated or is projected to operate, and divided by 2,000 lb/ton.

(5) The permitting authority will review, and allocate NOx allowances pursuant to, each NOx allowance allocation request under paragraph (d)(2) of this section in the order that the request is received by the permitting authority.

(i) Upon receipt of the NOx allowance allocation request, the permitting authority will make any necessary adjustments to the request to ensure that, for a unit under §96.4(a)(1) *[or non-emitting generating system]*, the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (3) of this section and, for a unit under §96.4(a)(2), the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (4) of this section.

(ii) If the allocation set-aside for the control period for which NOx allowances are requested has an amount of NOx allowances not less than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will allocate the amount of the NOx allowances requested (as adjusted under paragraph (d)(5)(i) of this section) to the unit *[or non-emitting generating system]*.

(iii) If the allocation set-aside for the control period for which NOx allowances are requested has a smaller amount of NOx allowances than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will deny in part the request and allocate only the remaining number of NOx allowances in the allocation set-aside to the unit *[or non-emitting generating system]*.

(iv) Once an allocation set-aside for a control period has been depleted of all NOx allowances, the permitting authority will deny, and will not allocate any NOx allowances pursuant to, any NOx allowance allocation request under which NOx allowances have not already been allocated for the control period.

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boiler efficiency of 70%, then this "efficiency" factor should be 77% or 0.77. If you use the simplified approach to monitoring output and assume a different boiler efficiency, divide the heat input-based allocation factor of 0.17 lb/mmBtu by the thermal output-based factor from Table II-1 in section II.A., p.29, to compute the appropriate "efficiency" factor.

(6) Within 60 days of receipt of a NOx allowance allocation request, the permitting authority will take appropriate action under paragraph (d)(5) of this section and notify the NOx authorized account representative that submitted the request and the Administrator of the number of NOx allowances (if any) allocated for the control period to the unit *[or non-emitting generating system]*.

(e) For a unit *[or non-emitting generating system]* allocated NOx allowances under paragraph (d) of this section for a control period, the Administrator will deduct NOx allowances under § 96.54(b) or (e) to account for the actual utilization or output of the unit *[or non-emitting generating system]* during the control period. The Administrator will calculate the number of NOx allowances to be deducted to account for the unit's actual utilization or output using the following formulas and rounding to the nearest whole number of NOx allowances as appropriate, provided that the number of NOx allowances to be deducted shall be zero if the number calculated is less than zero:

NOx allowances deducted for actual utilization for a unit under §96.4(a)(1) for a control period in 2003, 2004, or 2005 = (NOx allowances allocated for control period) - (Actual control period heat input x 0.15 lb/mmBtu ÷2,000 lb/ton);

NOx allowances deducted for actual output for a unit under §96.4(a)(1) *[or a non-emitting generating system]* for a control period in 2006 or thereafter = (Unit's NOx allowances allocated for control period) - (Unit's actual control period *{specify net or gross}* electric output x 1.5 lb/MWh ÷2,000 lb/ton and actual control period *{specify net or gross}* thermal output x 0.24 $lb/mmBtu_{out}$[38] ÷2,000 lb/ton); and

NOx allowances deducted for actual utilization for a unit under §96.4(a)(2) in 2003, 2004, or 2005= (NOx allowances allocated for control period) - (Actual control period heat input x 0.17 lb/mmBtu ÷2,000 lb/ton); and

NOx allowances deducted for actual output for a unit under §96.4(a)(2) for a control period in 2006 or thereafter= (NOx allowances allocated for control period) - (Actual control period *{specify net or gross}* thermal output x 0.24 lb/mmBtu[39] ÷2,000 lb/ton and actual control period *{specify net or gross}* electric output x 1.5 lb/MWh ÷ 2,000 lb/ton)

[38] Same as footnote 34.

[39] Same as footnote 34.

where:

"NOx allowances allocated for control period" is the number of NOx allowances allocated to the unit *[or the non-emitting generating system]* for the control period; and

"Actual control period heat input" is the heat input (in mmBtu) of the unit during the control period; and

"Actual control period *{specify net or gross}* electric output" is the *{specify net or gross}* electric output in MWh of the unit *[or non-emitting generating system]* during the control period; and

"Actual control period *{specify net or gross}* thermal output" is the *{specify net or gross}* thermal output in $mmBtu_{out}$ of the unit during the control period.

(f) After making the deductions for compliance under § 96.54(b) or (e) for a control period, the Administrator will notify the permitting authority whether any NOx allowances remain in the allocation set-aside for the control period. The permitting authority will allocate any such NOx allowances to the units under §96.4 *[and the non-emitting generating systems]* in [the State] *{insert name of your State}* using the following formula and rounding to the nearest whole number of NOx allowances as appropriate:

Unit's *[or non-emitting generating system's]* share of NOx allowances remaining in allocation set-aside = Total NOx allowances remaining in allocation set-aside x (NOx allowance allocation ÷ State trading program budget excluding allocation set-aside)

where:

"Total NOx allowances remaining in allocation set-aside" is the total number of NOx allowances remaining in the allocation set-aside for the control period;

" NOx allowance allocation" is the number of NOx allowances allocated under paragraph (b) or (c) of this section to the unit *[or non-emitting generating system]* for the control period to which the allocation set-aside applies; and

"State trading program budget excluding allocation set-aside" is the State trading program budget for the control period to which the allocation set-aside applies multiplied by 95 percent if the control period is in 2003, 2004, or 2005 or 98 percent if the control period is in any year thereafter, rounded to the nearest whole number of NOx allowances as appropriate.

Case 3

You initially allocate and periodically update allocations to EGUs based on output and to non-EGUs based on heat input

§ 96.42 NOx allowance allocations.

(a) *Basis for allocation.* The permitting authority will calculate NOx allowance allocations for each NOx Budget unit under § 96.4 [*or non-emitting generating system*] as follows:

(1) For a NOx allowance allocation for 2003 through 2005 under §96.41(a):

(i) The permitting authority will use the average of the two highest amounts of the unit's [*or non-emitting generating system's*] *{specify net or gross}* electric output (in MWh) and *{specify net or gross}* thermal output (in mmBtu output) for the control periods in 1995, 1996, and 1997 if the unit [*or non-emitting generating system*] is under §96.4(a)(1), or the unit's heat input for the control period in 1995 if the unit is under §96.4(a)(2); or

(ii) For a unit under §96.4(a)(1) [*or non-emitting generating system*] that commences operation on or after May 1, 1997, the permitting authority will use the unit's [*or non-emitting generating system's*] *{specify net or gross}* output, in accordance with paragraph (d) of this section. For a unit under §96.4(a)(2) that commences operation on or after May 1, 1995, ther permitting authority will use the unit's heat input, in accordance with paragraph (d) of this section.

(2) For a NOx allowance allocation for any year after 2005 under §96.41(b):

(i) The permitting authority will use the *{specify net or gross}* electric and thermal output for the unit under §96.4(a)(1) *[or the non-emitting generating system]*, and heat input for the unit under §96.4(a)(2) for the control period in the year that is four years before the year for which the NOx allocation is being calculated; or

(ii) For a unit *[or non-emitting generating system]* that commences operation on or after May 1 of the year that is four years before the year for which the permitting authority allocates, the permitting authority will determine allocations in accordance with paragraph (d) of this section.

(3) The permitting authority will determine the unit's heat input:

(i) In accordance with 40 CFR part 75; or

(ii) Based on the best available data reported to the permitting authority for the unit, if the unit was not otherwise subject to the requirements of 40 CFR part 75 for the control period.

(4) The permitting authority will determine the *{specify gross or net}* thermal and *{specify gross or net}* electric output for the unit [*or non-emitting generating system]* using {*insert source of data–e.g., net electric generation data from the Energy Information Administration, gross electric generation data in accordance with subpart H of 40 CFR part 75, electric generation data in accordance with subpart H of 40 CFR part 75, or the best available data reported to the permitting authority for the unit or non-emitting generating system.}*

(b) *Allocation to units under §96.4(a)(1)[and non-emitting generating systems]*. For each control period in 2003 through 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(1) [*or non-emitting generating system*] in [the State] *{substitute name of your State}* that commenced operation before May 1, 1997. For each control period after 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(1) *[or non-emitting generating systems]* in [the State] *{substitute name of your State}* that commenced operation before May 1 of the period used to calculate electric and thermal output under paragraph (a)(2) of this section. The permitting authority will calculate NOx allowance allocations as follows:

(1) The permitting authority will allocate NOx allowances to each unit under §96.4(a)(1) *[and to each non-emitting generating system]* in an amount equaling: 1.5 lb/MWh multiplied by the *{specify net or gross}* electric output under paragraph (a) of this section and divided by 2,000 lb/ton, plus 0.24 lb/$mmBtu_{out}$[40] multiplied by the *{specify net or gross}* thermal output under paragraph (a) of this section and divided by 2,000 lb/ton. Each allocation will be rounded to the nearest whole number of NOx allowances, as appropriate.

(2) For the control periods 2003, 2004, and 2005, the permitting authority will adjust the

[40]Use the value of 0.24 lb/mmBtu output if you assume a typical boiler efficiency of 70% and if you require sources to use the boiler efficiency approach for measuring thermal output, as described in section VI. of this document (pp. 68-69, 84-91, and 124-137). If you decide to use the simplified approach for monitoring output and a typical boiler efficiency of 70%, then this number should be 0.22 lb/mmBtu. If you want to assume a different typical boiler efficiency, see section II.A. to calculate your own allocation factor (pp. 23-31).

initial allocations under paragraph (b)(1) of this section so that the total number of NOx allowances allocated for 2003, 2004, or 2005 equals 95 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's allocation for 2003, 2004, or 2005 by 95 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1) divided by the total number of NOx allowances allocated under paragraph (b)(1) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(3) For each control period after 2005, the permitting authority will adjust the initial allocations under paragraph (b)(1) of this section so that the total number of NOx allowances allocated for each control period after 2005 equals 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's allocation for a control period after 2005 by 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1) divided by the total number of NOx allowances allocated under paragraph (b)(1) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(c) *Allocation to units under §96.4(a)(2).* For each control period under § 96.41, the permitting authority will allocate NOx allowances to all units under §96.4(a)(2) in [the State] *{insert name of State}* that commenced operation before May 1 of the period used to calculate heat input under paragraph (a) of this section. The permitting authority will allocate NOx allowances in accordance with the following procedures:

(1) The permitting authority will allocate NOx allowances to each NOx Budget unit under §96.4(a)(2) in an amount equaling 0.17 lb/mmBtu multiplied by the heat input under paragraph (a) of this section, divided by 2,000 lb/ton. Each allocation will be rounded to the nearest whole number of NOx allowances, as appropriate.

(2) The permitting authority will adjust the unadjusted allocations under paragraph (c)(1) of this section so that the total number of NOx allowances allocated equals 95 percent in 2003, 2004, and 2005, or 98 percent thereafter, of the number of tons of NOx emissions in the State trading

program budget apportioned to units under §96.4(a)(2), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's for a control period by 95 percent in 2003, 2004, or 2005, or by 98 percent thereafter, of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(2), dividing by the total number of NOx allowances allocated under paragraph (c)(1) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(d) For each control period under § 96.41, the permitting authority will allocate NOx allowances to NOx Budget units under § 96.4 *[or non-emitting generating systems]* in [the State] *{insert name of your State}* that commenced operation, or are projected to commence operation, on or after May 1 of the period used to calculate heat input or electric and thermal output under paragraph (a) of this section, in accordance with the following procedures:

(1) The permitting authority will establish one allocation set-aside for each control period. Each allocation set-aside will be allocated NOx allowances equal to 5 percent in 2003, 2004, and 2005, or 2 percent thereafter, of the tons of NOx emissions in the State trading program budget, rounded to the nearest whole number of NOx allowances, as appropriate.

(2) The NOx authorized account representative of a unit *[or non-emitting generating system]* under paragraph (d) of this section may submit to the permitting authority a request, in writing or in a format specified by the permitting authority, to be allocated NOx allowances for no more than five consecutive control periods under § 96.41, starting with the control period during which the unit *[or non-emitting generating system]* commenced, or is projected to commence, operation and ending with the control period preceding the control period for which it will receive an allocation under paragraph (b) or (c) of this section. The NOx allowance allocation request must be submitted prior to May 1 of the first control period for which the NOx allowance allocation is requested and after the date on which the permitting authority issues a permit to construct the unit *[or non-emitting generating system]*.

(3) In a NOx allowance allocation request under paragraph (d)(2) of this section, the NOx authorized account representative for a unit under §96.4(a)(1) *[or a non-emitting generating system]* may request NOx allowances for a control period. The requested number of NOx allowances must not exceed 1.5 lb/MWh multiplied by the nameplate capacity (in MW) of the unit *[or non-emitting*

generating system], multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate, and divided by 2,000 lb/ton.

(4) In a NOx allowance allocation request under paragraph (d)(2) of this section, the NOx authorized account representative for a unit under §96.4(a)(2) may request NOx allowances for a control period. The requested number of NOx allowances must not exceed 0.17 lb/mmBtu multiplied by the unit's maximum design heat input (in mmBtu/hr), multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate, and divided by 2,000 lb/ton.

(5) The permitting authority will review, and allocate NOx allowances pursuant to, each NOx allowance allocation request under paragraph (d)(2) of this section in the order that the request is received by the permitting authority.

(i) Upon receipt of the NOx allowance allocation request, the permitting authority will make any necessary adjustments to the request to ensure that, for a unit under §96.4(a)(1) *[or non-emitting generating system]*, the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (3) of this section and, for a unit under §96.4(a)(2), the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (4) of this section.

(ii) If the allocation set-aside for the control period for which NOx allowances are requested has an amount of NOx allowances not less than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will allocate the amount of the NOx allowances requested (as adjusted under paragraph (d)(5)(i) of this section) to the unit *[or non-emitting generating system]*.

(iii) If the allocation set-aside for the control period for which NOx allowances are requested has a smaller amount of NOx allowances than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will deny in part the request and allocate only the remaining number of NOx allowances in the allocation set-aside to the unit *[or non-emitting generating system]*.

(iv) Once an allocation set-aside for a control period has been depleted of all NOx allowances, the permitting authority will deny, and will not allocate any NOx allowances pursuant to, any NOx allowance allocation request under which NOx allowances have not already been allocated for the control period.

(6) Within 60 days of receipt of a NOx allowance allocation request, the permitting authority will take appropriate action under paragraph (d)(5) of this section and notify the NOx authorized account representative that submitted the request and the Administrator of the number of NOx allowances (if any) allocated for the control period to the unit *[or non-emitting generating system]*.

(e) For a unit *[or non-emitting generating system]* allocated NOx allowances under paragraph (d) of this section for a control period, the Administrator will deduct NOx allowances under § 96.54(b) or (e) to account for the actual utilization or output of the unit *[or non-emitting generating system]* during the control period. The Administrator will calculate the number of NOx allowances to be deducted to account for the unit's actual utilization or output using the following formulas and rounding to the nearest whole number of NOx allowances as appropriate, provided that the number of NOx allowances to be deducted shall be zero if the number calculated is less than zero:

NOx allowances deducted for actual output for a unit under §96.4(a)(1) *[or a non-emitting generating system]* = (Unit's NOx allowances allocated for control period) - (Unit's actual control period *{specify net or gross}* electric output x 1.5 lb/MWh ÷2,000 lb/ton and actual control period *{specify net or gross}* thermal output x 0.24 $lb/mmBtu_{out}$[41] ÷2,000 lb/ton); and

NOx allowances deducted for actual utilization for a unit under §96.4(a)(2)= (NOx allowances allocated for control period) - (Actual control period heat input x 0.17 lb/mmBtu ÷2,000 lb/ton)

where:

"NOx allowances allocated for control period" is the number of NOx allowances allocated to the unit *[or the non-emitting generating system]* for the control period; and

"Actual control period heat input" is the heat input (in mmBtu) of the unit during the control period; and

"Actual control period *{specify net or gross}* electric output" is the *{specify net or gross}* electric output in MWh of the unit *[or non-emitting generating system]* during the control period;

[41]Same as footnote 40.

and

"Actual control period *{specify net or gross}* thermal output" is the *{specify net or gross}* thermal output in $mmBtu_{out}$ of the unit during the control period.

(f) After making the deductions for compliance under § 96.54(b) or (e) for a control period, the Administrator will notify the permitting authority whether any NOx allowances remain in the allocation set-aside for the control period. The permitting authority will allocate any such NOx allowances to the units under §96.4 *[and the non-emitting generating systems]* in [the State] *{insert name of your State}* using the following formula and rounding to the nearest whole number of NOx allowances as appropriate:

Unit's *[or non-emitting generating system's]* share of NOx allowances remaining in allocation set-aside = Total NOx allowances remaining in allocation set-aside x (NOx allowance allocation ÷ State trading program budget excluding allocation set-aside)

where:

"Total NOx allowances remaining in allocation set-aside" is the total number of NOx allowances remaining in the allocation set-aside for the control period;

" NOx allowance allocation" is the number of NOx allowances allocated under paragraph (b) or (c) of this section to the unit *[or non-emitting generating system]* for the control period to which the allocation set-aside applies; and

"State trading program budget excluding allocation set-aside" is the State trading program budget for the control period to which the allocation set-aside applies multiplied by 95 percent if the control period is in 2003, 2004, or 2005 or 98 percent if the control period is in any year thereafter, rounded to the nearest whole number of NOx allowances as appropriate.

Case 4

You initially allocate and periodically update allocations to both EGUs and non-EGUs based on output

§ 96.42 NOx allowance allocations.

(a) *Basis for allocation.* The permitting authority will calculate NOx allowance allocations for each NOx Budget unit under § 96.4 [*or non-emitting generating system*] as follows:

(1) For a NOx allowance allocation for 2003 through 2005 under §96.41(a):

(i) The permitting authority will use the average of the two highest amounts of the unit's [*or non-emitting generating system's*] *{specify net or gross}* electric output (in MWh) and *{specify net or gross}* thermal output (in mmBtu output) for the control periods in 1995, 1996, and 1997 if the unit [*or non-emitting generating system*] is under §96.4(a)(1), or the unit's *{specify net or gross}* thermal output (in mmBtu output) and *{specify net or gross}* electric output (in MWh) for the control period in 1995 if the unit is under §96.4(a)(2); or

(ii) For a unit under §96.2(a)(1) [*or non-emitting generating system*] that commences operation on or after May 1, 1997, or for a unit under §96.4(a)(2) that commences operation on or after May 1, 1995, the permitting authority will use the unit's [*or non-emitting generating system's*] electric output or thermal output in accordance with paragraph (d) of this section.

(2) For a NOx allowance allocation for any year after 2005 under §96.41(b):

(i) The permitting authority will use the *{specify net or gross}* electric and thermal output for the unit *[or the non-emitting generating system]* for the control period in the year that is four years before the year for which the NOx allocation is being calculated; or

(ii) For a unit *[or non-emitting generating system]* that commences operation on or after May 1 of the year that is four years before the year for which the permitting authority allocates, the permitting authority will determine allocations in accordance with paragraph (d) of this section.

(3) The permitting authority will determine the *{specify gross or net}* thermal and electric output for the unit [*or the non-emitting generating system]* using *{insert source of data–e.g., net electric generation data from the Energy Information Administration, gross electric generation data in accordance with subpart H of 40 CFR part 75, electric generation data in accordance with*

subpart H of 40 CFR part 75, or the best available data reported to the permitting authority for the unit [or the non-emitting generating system].}

(b) *Allocation to units under §96.4(a)(1)[and non-emitting generating systems]*. For each control period in 2003 through 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(1) [*or non-emitting generating system*s] in [the State] *{substitute name of your State}* that commenced operation before May 1, 1997. For each control period after 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(1) *[or non-emitting generating systems]* in [the State] *{substitute name of your State}* that commenced operation before May 1 of the period used to calculate electric and thermal output under paragraph (a)(2) of this section. The permitting authority will calculate NOx allowance allocations as follows:

(1) For each control period, the permitting authority will allocate NOx allowances to each unit under §96.4(a)(1) *[and to each non-emitting generating system]* in an amount equaling: 1.5 lb/MWh multiplied by the *{specify net or gross}* electric output under paragraph (a) of this section and divided by 2,000 lb/ton, plus 0.24 lb/$mmBtu_{out}$[42] multiplied by the *{specify net or gross}* thermal output under paragraph (a) of this section and divided by 2,000 lb/ton. Each allocation will be rounded to the nearest whole number of NOx allowances, as appropriate.

(2) For 2003 through 2005, the permitting authority will adjust the initial allocations under paragraph (b)(1) of this section so that the total number of NOx allowances allocated for 2003, 2004, or 2005 equals 95 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's allocation for 2003, 2004, or 2005 by 95 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1), dividing by the total number of NOx allowances allocated for the year under

[42]Use the value of 0.24 lb/mmBtu output if you assume a typical boiler efficiency of 70% and if you require sources to use the boiler efficiency approach for measuring thermal output, as described in section VI. of this document (pp. 68-69, 84-91, and 124-137). If you decide to use the simplified approach for monitoring output and a typical boiler efficiency of 70%, then this number should be 0.22 lb/mmBtu. If you want to assume a different typical boiler efficiency, see section II.A. to calculate your own allocation factor (pp. 23-31).

paragraph (b)(1) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(3) For each control period after 2005, the permitting authority will adjust the initial allocations under paragraph (b)(1) of this section so that the total number of NOx allowances allocated for each control period after 2005 equals 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's allocation for a control period after 2005 by 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(1) divided by the total number of NOx allowances allocated under paragraph (b)(1) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(c) *Allocation to units under §96.4(a)(2).* For 2003 through 2005, the Department will allocate NOx allowances to all NOx Budget units under §96.4(a)(2) in [the State] *{substitute name of your State}* that commenced operation before May 1, 1995. For each control period after the year 2005, the permitting authority will allocate NOx allowances to all NOx Budget units under §96.4(a)(2) in [the State] *{substitute name of your State}* that commenced operation before May 1 of the period used to calculate electric and thermal output under paragraph (a)(2) of this section. The permitting authority will calculate NOx allowance allocations as follows:

(1) The permitting authority will allocate NOx allowances to each unit under §96.4(a)(2) in an amount equaling: 0.24 lb/$mmBtu_{out}$[43] multiplied by the *{specify net or gross}* thermal output under paragraph (a) of this section and divided by 2,000 lb/ton, plus 1.5 lb/MWh multiplied by the *{specify net or gross}* electric output under paragraph (a) of this section and divided by 2,000 lb/ton. Each allocation will be rounded to the nearest whole number of NOx allowances, as appropriate.

(2) For 2003 through 2005, the permitting authority will adjust the unadjusted allocations under paragraph (c)(1) of this section so that the total number of NOx allowances allocated equals 95 percent in 2003, 2004, or 2005, of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(2), if these numbers are not already equal. This

[43]Same as footnote 42.

adjustment will be made by: multiplying each unit's allocation in 2003, 2004, or 2005 by 95 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(2), dividing by the total number of NOx allowances allocated under paragraph (c)(1) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(3) For each control period after 2005, the permitting authority will adjust the initial allocations under paragraph (c)(1) of this section so that the total number of NOx allowances allocated for each control period after 2005 equals 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(2), if these numbers are not already equal. This adjustment will be made by: multiplying each unit's allocation for a control period after 2005 by 98 percent of the number of tons of NOx emissions in the State trading program budget apportioned to units under §96.4(a)(2) and dividing by the total number of NOx allowances allocated under paragraph (c)(1) of this section, and rounding to the nearest whole number of NOx allowances, as appropriate.

(d) For each control period under § 96.41, the permitting authority will allocate NOx allowances to NOx Budget units under § 96.4 *[or non-emitting generating systems]* in [the State] *{insert name of your State}* that commenced operation, or are projected to commence operation, on or after May 1 of the period used to calculate electric and thermal output under paragraph (a) of this section, in accordance with the following procedures:

(1) The permitting authority will establish one allocation set-aside for each control period. Each allocation set-aside will be allocated NOx allowances equal to 5 percent in 2003, 2004, and 2005, or 2 percent thereafter, of the tons of NOx emissions in the State trading program budget, rounded to the nearest whole number of NOx allowances, as appropriate.

(2) The NOx authorized account representative of a unit *[or non-emitting generating system]* under paragraph (d) of this section may submit to the permitting authority a request, in writing or in a format specified by the permitting authority, to be allocated NOx allowances for no more than five consecutive control periods under § 96.41, starting with the control period during which the unit *[or non-emitting generating system]* commenced, or is projected to commence, operation and ending with the control period preceding the control period for which it will receive an allocation under paragraph (b) or (c) of this section. The NOx allowance allocation request must be submitted prior

to May 1 of the first control period for which the NOx allowance allocation is requested and after the date on which the permitting authority issues a permit to construct the unit *[or non-emitting generating system]*.

(3) In a NOx allowance allocation request under paragraph (d)(2) of this section, the NOx authorized account representative for a unit under §96.4(a)(1) *[or a non-emitting generating system]* may request NOx allowances for a control period. The requested number of NOx allowances must not exceed 1.5 lb/MWh multiplied by the nameplate capacity (in MW) of the unit *[or non-emitting generating system]*, multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate, and divided by 2,000 lb/ton.

(4) In a NOx allowance allocation request under paragraph (d)(2) of this section, the NOx authorized account representative for a unit under §96.4(a)(2) may request NOx allowances for a control period. The requested number of NOx allowances must not exceed 0.24 $lb/mmBtu_{out}$,[44] multiplied by the maximum design heat input of the unit (in mmBtu/hr), divided by an efficiency factor of 0.70,[45] multiplied by the number of hours remaining in the control period starting with the first day in the control period on which the unit operated or is projected to operate, and divided by 2,000 lb/ton.

(5) The permitting authority will review, and allocate NOx allowances pursuant to, each NOx allowance allocation request under paragraph (d)(2) of this section in the order that the request is received by the permitting authority.

(i) Upon receipt of the NOx allowance allocation request, the permitting authority will make any necessary adjustments to the request to ensure that, for a unit under §96.4(a)(1) *[or non-emitting*

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[44] Same as footnote 42.

[45] This efficiency factor of 0.70 is appropriate for use with the boiler efficiency approach for measuring output, as described in section VI. of this document (pp. 68-69, 84-91, and 124-137). If you decide to use the simplified approach for monitoring thermal output and a typical boiler efficiency of 70%, then this "efficiency" factor should be 77% or 0.77. If you use the simplified approach to monitoring output and assume a different boiler efficiency, divide the heat input-based allocation factor of 0.17 lb/mmBtu by the thermal output-based factor from Table II-1 in section II.A., p. 29 to compute the appropriate "efficiency" factor.

generating system], the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (3) of this section and, for a unit under §96.4(a)(2), the control period and the number of allowances specified are consistent with the requirements of paragraphs (d)(2) and (4) of this section.

(ii) If the allocation set-aside for the control period for which NOx allowances are requested has an amount of NOx allowances not less than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will allocate the amount of the NOx allowances requested (as adjusted under paragraph (d)(5)(i) of this section) to the unit *[or non-emitting generating system]*.

(iii) If the allocation set-aside for the control period for which NOx allowances are requested has a smaller amount of NOx allowances than the number requested (as adjusted under paragraph (d)(5)(i) of this section), the permitting authority will deny in part the request and allocate only the remaining number of NOx allowances in the allocation set-aside to the unit *[or non-emitting generating system]*.

(iv) Once an allocation set-aside for a control period has been depleted of all NOx allowances, the permitting authority will deny, and will not allocate any NOx allowances pursuant to, any NOx allowance allocation request under which NOx allowances have not already been allocated for the control period.

(6) Within 60 days of receipt of a NOx allowance allocation request, the permitting authority will take appropriate action under paragraph (d)(5) of this section and notify the NOx authorized account representative that submitted the request and the Administrator of the number of NOx allowances (if any) allocated for the control period to the unit *[or non-emitting generating system]*.

(e) For a unit *[or non-emitting generating system]* allocated NOx allowances under paragraph (d) of this section for a control period, the Administrator will deduct NOx allowances under § 96.54(b) or (e) to account for the actual output of the unit *[or non-emitting generating system]* during the control period. The Administrator will calculate the number of NOx allowances to be deducted to account for the unit's actual output using the following formulas and rounding to the nearest whole number of NOx allowances as appropriate, provided that the number of NOx allowances to be deducted shall be zero if the number calculated is less than zero:

NOx allowances deducted for actual output for a unit under §96.4(a)(1) *[or a non-emitting generating system]* = (Unit's NOx allowances allocated for control period) - (Unit's actual control period *{specify net or gross}* electric output x 1.5 lb/MWh ÷2,000 lb/ton and actual control period *{specify net or gross}* thermal output x 0.24 lb/mmBtu$_{out}$[46] ÷2,000 lb/ton); and

NOx allowances deducted for actual output for a unit under §96.4(a)(2)= (NOx allowances allocated for control period) - (Actual control period *{specify net or gross}* thermal output x 0.24 lb/mmBtu$_{out}$[47] ÷2,000 lb/ton and actual control period *{specify net or gross}* electric output x 1.5 lb/MWh ÷ 2,000 lb/ton)

where:

"NOx allowances allocated for control period" is the number of NOx allowances allocated to the unit *[or the non-emitting generating system]* for the control period; and

"Actual control period *{specify net or gross}* electric output" is the *{specify net or gross}* electric output in MWh of the unit *[or non-emitting generating system]* during the control period; and

"Actual control period *{specify net or gross}* thermal output" is the *{specify net or gross}* thermal output in mmBtu$_{out}$ of the unit during the control period.

(f) After making the deductions for compliance under § 96.54(b) or (e) for a control period, the Administrator will notify the permitting authority whether any NOx allowances remain in the allocation set-aside for the control period. The permitting authority will allocate any such NOx allowances to the units under §96.4 *[and the non-emitting generating systems]* in [the State] *{insert name of your State}* using the following formula and rounding to the nearest whole number of NOx allowances as appropriate:

Unit's *[or non-emitting generating system's]* share of NOx allowances remaining in allocation set-aside = Total NOx allowances remaining in allocation set-aside x (NOx allowance allocation ÷ State trading program budget excluding allocation set-aside)

where:

[46] Same as footnote 42.

[47] Same as footnote 42.

"Total NOx allowances remaining in allocation set-aside" is the total number of NOx allowances remaining in the allocation set-aside for the control period;

" NOx allowance allocation" is the number of NOx allowances allocated under paragraph (b) or (c) of this section to the unit *[or non-emitting generating system]* for the control period to which the allocation set-aside applies; and

"State trading program budget excluding allocation set-aside" is the State trading program budget for the control period to which the allocation set-aside applies multiplied by 95 percent if the control period is in 2003, 2004, or 2005 or 98 percent if the control period is in any year thereafter, rounded to the nearest whole number of NOx allowances as appropriate.

Appendix B: Glossary of terms used in this guidance

add-on pollution controls –a pollution reduction control technology that operates independent of the combustion process. Examples: selective catalytic reduction, scrubber

adjusted allocation–an allocation that has been increased or decreased in proportion to a unit, source or generator's share of all operation from a group of units or sources with a budget. For example, an electric generating unit's initial allocation could be increased if the sum of the initial allocations for all units in the EGU sector was less than the budget for the EGU sector. Each unit would then have its allocation increased so that it would have the same fraction of the EGU sector budget as it has a fraction of total electric generation in the EGU sector in the state.

AGA-American Gas Association

allocation-the number of NOx allowances the permitting authority assigns to a unit or a set-aside. Section 96.2 of the model rule for the NOx Budget Trading Program defines an allocation as "the determination by the permitting authority or the Administrator of the number of NOx allowances to be initially credited to a NOx Budget unit or an allocation set-aside."

allowance-an authorization to emit up to one ton of a pollutant during the control period of the specified year or of any year thereafter. For the NOx Budget Trading Program, the authorization is from the permitting authority or the Administrator to emit up to one ton of NOx.

ANSI-American National Standards Institute

ASME-American Society for Mechanical Engineering

ASTM-American Society for Testing and Materials *auxiliary load*–electric generation used internally as part of operations of the unit, fuel feed equipment, fans, belts, or generator.

baseline period–the period of time from which historical operating information comes, which is then used as the basis for allocations. Section 96.42 of the model rule for the NOx Budget Trading Program under the NOx SIP call uses the control periods of 1995, 1996, and 1997 as the baseline period for allocations for 2003, 2004, and 2005.

boiler-an enclosed fossil or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

boiler efficiency-- a measure of the efficiency of a steam generating system which calculates efficiency as the energy imparted to the steam from combustion (mmBtu) divided by the boiler heat input due to combustion of fuel (mmBtu). A monitoring system which determines the energy imparted to the steam leaving the boiler tubes by calculating the balance of energy on thermal energy leaving and entering the boiler measures boiler efficiency.

boiler efficiency approach– an approach to monitoring thermal output that determines the energy imparted to the steam leaving the boiler tubes by calculating the balance of energy on thermal energy leaving and entering the boiler through steam or hot water output and boiler input water. This approach assumes that efficiency is calculated using an energy balance that subtracts hot water or steam's energy from the thermal energy leaving a boiler, and is divided by the boiler heat input from combustion of fuel.

boiler feedwater return or *feedwater*–the condensed water entering a boiler to be reheated that previously came from the boiler. This condensate return adds thermal energy to water going into the boiler.

Btu/kWh– British thermal units per kilowatt-hour *buss bar*–the point where electricity leaves a power plant to go to the grid.

combined cycle system--a system comprised of a combustion turbine, one or more heat recovery steam generators, and steam turbines configured to improve overall efficiency of electricity generation or steam production.

CEMS or *continuous emission monitoring systems*-- Equipment for continuously measuring and recording characteristics of pollutants in stack gas, such as the NOx concentration, NOx emission rate in lb/mmBtu, stack flow rate, or NOx mass. In section 96.2 of the model rule for the NOx Budget Trading Program for the NOx SIP call, CEMS are "the equipment required under subpart H of [40 CFR part 96] to sample, analyze, measure, and provide, by readings taken at least once every 15 minutes of the measured parameters, a permanent record of nitrogen oxides emissions, expressed in tons per hour for nitrogen oxides...." Under the NOx SIP call, CEMS must meet the applicable requirements of 40 CFR part 75.

cement kiln–a device which heats and processes cement.

CFR–Code of Federal Regulations

Cogeneration unit–a unit that produces electric energy and useful thermal energy for industrial, commercial, or residential heating or cooling purposes, through the sequential use of the original fuel energy.

CHP or *combined heat and power* or *Cogeneration*--producing electric energy and useful thermal energy for industrial, commercial, or residential heating or cooling purposes, through the sequential use of the original fuel energy.

CT or *combustion turbine*-- an enclosed fossil or other fuel-fired device that is comprised of a compressor, a combustor, and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine.

condensate–water that is created when steam condenses.

DAHS or *data acquisition and handling system*-- the computerized system for receiving, calculating, recording, and reporting emissions and operating data in appropriate units of measure. Section 96.2 of the model rule for the NOx Budget Trading Program defines DAHS as “that component of the CEMS, or other emissions monitoring system approved for use under subpart H of [40 CFR part 96], designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart H of [40 CFR part 96].

EDR or *electronic data reporting*-- EPA’s standardized format for electronic data reporting.

EGU–electric generating unit. For purposes of this document, a fossil fuel-fired unit that serves an electric generator greater than 25 MWe and produces electricity for sale.

EIA– Energy Information Administration

electric output--the electric generation (in MWh) from an electric generator.

EF–degrees Fahrenheit

fossil fuel-- natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

fossil fuel-fired–burning mostly fossil fuels. Section 96.2 of the model rule for the NOx

Budget Trading Program defines fossil fuel-fired as "with regard to a unit:
(1) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel actually combusted comprises more than 50 percent of the annual heat input on a Btu basis during any year starting in 1995 or, if a unit had no heat input starting in 1995, during the last year of operation of the unit prior to 1995; or
(2) The combustion of fossil fuel, alone or in combination with any other fuel, where fossil fuel is projected to comprise more than 50 percent of the annual heat input on a Btu basis during any year; provided that the unit shall be "fossil fuel-fired" as of the date, during such year, on which the unit begins combusting fossil fuel. "

grid–a system for transmitting or distributing electricity.

gross output--the total energy output of a process before making any deductions for any energy output consumed in any way related to producing energy through that process.

heat input–thermal energy going into a process through combustion of fuel. Section 96.2 of the model rule for the NOx Budget Trading Program defines heat input as "the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) and the fuel feed rate into a combustion device (in mass of fuel/time), as measured, recorded, and reported to the Administrator by the NOx authorized account representative and as determined by the Administrator in accordance with subpart H of [40 CFR part 96], and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources."

heat rate–the efficiency of producing electricity from combustion of fuel, in Btu/kWh.

house load–electric generation or thermal energy generation used internally within the facility where the electricity or thermal energy is generated.

HRSG or *heat recovery steam generator*–a device for recovering heat left after generating electricity with a turbine and using the recovered heat to produce steam.

IEEE-Institute of Electrical and Electronics Engineers

industrial boiler or turbine–a boiler or turbine used to provide thermal energy, or in some cases electricity, to operate an industrial process.

institutional boiler or turbine–a boiler or turbine used to provide thermal energy, or in some cases electricity, to operate a process for a non-industrial institution, such as a hospital, government office, or school.

klb/hr–thousands of pounds per hour

lb/mmBtu heat input– pounds of pollutant per measured million British thermal units of heat input

lb/mmBtu$_{out}$–pounds of pollutant emitted per measured million British thermal units of thermal output

lb/MWh–pounds of pollutant per megawatt-hour

make up water–relatively cold water that is mixed with any returned condensate before feeding water into the boiler.

mmBtu–million British thermal units

model rule or model rule for the NOx Budget Trading Program–the optional model rule EPA prepared for States that would comply with the NOx SIP call by joining the NOx Budget Trading Program, found at 40 CFR part 96.

MWh–megawatt-hour

nameplate capacity–the maximum electric generation an electric generator has been designed to sustain. Section 96.2 of the model rule for the NOx Budget Trading Program defines nameplate capacity as “the maximum electrical generating output (in MWe) that a generator can sustain over a specified period of time when not restricted by seasonal or other deratings as measured in accordance with the United States Department of Energy standards.”

net output--the final output of a process after deducting any output consumed in any way related to producing energy through that process. Examples of output to be deducted include thermal output lost through radiation to the outside, thermal output used for air or feedwater preheating, or thermal or electric output used within the plant to operate the unit, generator, fuel handling system, pumps, fans, or emission control equipment. Output used to produce a useful material product besides the thermal output or electric output, such as thermal energy used to dry paper, does not need to be deducted when calculating net output.

new source set-aside–a portion of allowances taken from a State budget for distribution to new sources instead of to existing sources.

NIST-National Institute for Standards and Technology (formerly the National Bureau of Standards).

non-EGU or *non-electric generating unit*–for purposes of this guidance, an industrial or institutional boiler or turbine.

non-emitting electric generating system or *non-emitting generating system*--the portion of a facility for generating electricity that uses an energy source not involving combustion of fuel or NOx emissions, such as hydroelectric, nuclear, geothermal, or wind power, and that uses an electric generator.

NOx–oxides of nitrogen (e.g., NO, NO_2)

NOx Budget Trading Program–the multi-state nitrogen oxides air pollution control and emission reduction program established under the NOx SIP call as a means of mitigating the interstate transport of ozone and nitrogen oxides, an ozone precursor.

NOx SIP call–EPA's requirement that States revise their State implementation plans to control NOx mass emissions in order to reduce interstate transport of ozone. See 63 FR 57355, October 27, 1998, Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone.

OTC-Ozone Transport Commission

OTC NOx Budget Program-a program organized by the Ozone Transport Commission for controlling NOx emissions in thirteen northeast States and the District of Columbia. EPA administers some portions of the program, such as allowance and emissions tracking.

output monitoring system--a collection of component pieces of equipment which are used together to get a measurement of electric or thermal output in the units of measure required under a regulation. An output monitoring system might consist of the following components:

- All wattmeters and a data logger that a company uses together to calculate electric output data for a unit (or facility).
- All flowmeters for steam or condensate, temperature measurement devices, absolute pressure measurement devices, and differential pressure devices for measuring thermal energy and a data logger that a company uses together to calculate thermal output data for a unit (or facility).

ozone season–the period from May 1 through September 30 of each year, inclusive.

parasitic loads–loads that are used within a plant to operate equipment that does not contribute to the final product being sold. Examples of parasitic loads are electric loads used to operate fuel handling and preparation equipment, pumps, compressors, motors, fans, or pollution control equipment, or thermal loads used in operating pumps or compressors.

psi–pounds per square inch

QA–quality assurance. The process of checking the quality of data, including tests on monitoring equipment.

saturated steam–steam at a temperature and pressure close to that of the normal boiling point for water such that the steam will easily condense. This is the normal state for water vapor under atmospheric pressure conditions. Industrial and institutional boilers typically produce saturated steam, while utility boilers typically produce superheated steam.

scrubber–a flue gas desulfurization system for controlling SO_2 emissions.

sector budget–the portion of the State budget associated with the electric generating unit sector or the non-electric generating unit sector.

simplified approach-- a simplified approach to monitoring output that measures the energy output of steam exiting a boiler without compensating for the energy already in the water entering the boiler. Under this approach a pseudo-efficiency may be determined by dividing the energy in the steam leaving the boiler by the heat input from combustion of fuel. This pseudo-efficiency does not take account of the law of conservation of energy and may result in an efficiency of greater than 1. A monitoring system using a simplified approach measures the total energy of steam exiting a boiler and does not require measuring or subtracting thermal energy in the boiler feedwater (condensate) return.

source–a plant or facility that produces air pollutants. Section 96.2 of the model rule for the NOx Budget Trading Program defines a source as " any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any regulated air pollutant under the Clean Air Act. For purposes of section 502(c) of the Clean Air Act, a "source," including a "source" with multiple units, shall be considered a single "facility."

State budget–the total number of tons of NOx emissions projected for each State in year 2007 under the NOx SIP call.

Superheated steam or supersaturated steam–steam at a temperature and pressure sufficiently higher than that for the normal boiling point for water that the steam will not condense. Utility boilers typically produce superheated steam so that the steam will not condense in the steam turbine that runs the electric generator.

thermal output--the thermal energy from a heat source (in $mmBtu_{out}$/time) that is available for use in another process after the subtraction of heat for boiler feed or combustion air preheating or other heat recovery for combustion

trading budget–the portion of the State budget used to allocate NOx allowances under the NOx Budget Trading Program.

unadjusted allocation–the tonnage initially calculated for a unit, source, or generator using an emission rate and operational data, before adjusting to the total number of allowances available for allocation.

unit–a fossil fuel-fired stationary boiler, combustion turbine, or combined cycle system.

Updating Output Emission Limitation Workgroup–the stakeholder workgroup that has advised EPA during development of this guidance document. The workgroup reports to the Clean Air, Energy and Climate Subcommittee of the Clean Air Act Advisory Committee.

updating allocation–an allocation that the permitting authority recalculates and uses to redistribute allowances using more current operational data.

Index